STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to implement the provisions of Section 10a(10) of 2000 PA 141.	)))	Case No. U-12639

QUALIFICATIONS

AND

REBUTTAL TESTIMONY

OF

EDWARD C. BODMER

Line No.

Q. What is your name and address and on whose behalf are you testifying?

A. My name is Edward C. Bodmer. My address is 5951 Oakwood Drive, Lisle IL. 60532. I am testifying on behalf of the Detroit Edison Company ("Edison" or the "Company").

Q. Summarize your educational background.

A. I received a B.S., with highest honors, in Finance from the University of Illinois in 1979 and an MBA, with honors, from the University of Chicago in 1986.

Q. Summarize your professional experience.

A. Since 1990 I have developed a consulting practice in the electric utility industry, which has involved assignments for municipal and investor owned utility companies, government agencies, energy consumers, financial institutions, and alternative retail electric suppliers. My projects have addressed issues related to industry re-structuring, forecasting, pricing, rate cap plans, resource planning and performance evaluation. I have testified before regulatory bodies in many states on a variety of subjects, including revenue requirements, cost of capital, cost-of-service and rate design. I have completed a number of assignments dealing with deregulation of electric utility generation, including an analysis of the

Line
No.

divestiture of generating assets, testimony on delivery service tariffs, and assistance in crafting legislation.

My regulatory experience began in 1979 with my employment on the Accounting and Finance Staff of the Illinois Commerce Commission, and has encompassed numerous assignments on regulatory issues for the Illinois Commission and later as a private consultant. From 1986 to 1990, I was employed at the money center bank (now named Bank One) where I managed the credit analysis of all energy loans, including transactions with electric and gas utility companies. I am an adjunct professor of economics at Lewis University in Romeoville, Illinois, and I have developed and taught specialized professional courses in financial modeling, options valuation, project finance, bankruptcy and economics throughout the world.

Appendix A includes a list of my previous testimony and a list of the professional courses that I have taught.

Line No.

Section One

Purpose Summary and Outline

Q. What is the purpose of your testimony in this proceeding?

A. Edison has asked me to comment on the valuation analysis used by certain intevenor witnesses that evaluate the relationship between the market value and the book value of generation resources for purposes of establishing transition charges to retail open access customers. In particular, the Company requested that I quantify the value impacts from Edison obligations and customer options included in Michigan's restructuring plan. My valuation discussion addresses testimony presented by Mr. Christopher D. Seiple, Mr. Francis A. Roberts, Dr. Richard D. Tabors, Mr. James T. Selecky, Mr. William A. Peloquin, Mr. Charles W. King, and Mr. Richard A. Polich.

The primary focus of my analysis is correction of valuations presented by intevenor witnesses so as to reflect Edison's obligation to provide both regulated service and direct access service. The overarching theme of my testimony is that intevenor witnesses have made very biased estimates of the value of Edison's generating plants because they neglect to directly consider the responsibility Edison has to allow customers to switch between bundled rates and market based prices. As I explain below, if the intevenor witnesses had accounted for volatility in electricity prices as well

Line No.

as Edison's obligation to provide service at regulated rates, their conclusions with respect to plant value would change by billions of dollars and their recommended transition charges would be dramatically different.

Q. How have you analyzed the valuation methods presented in the intevenor testimony?

A. My testimony considers analytical fallacies that arise using the discounted cash flow valuation technique employed by Mr. Christopher Seiple and the comparable sales transaction approach presented by Dr. Richard Tabors in light of the rights provided by Edison to its customers. The most significant problem with these two methods is that they ignore the value gained by customers -- and lost by Detroit Edison -- from the "insurance policy" Michigan customers have to return to regulated tariffs when market prices increase. Evaluation of the relationship between market and book value of generating plants in Michigan must instead apply option-pricing concepts as a central component of the analysis.

My corrections to the intevenor analyses encompass the following issues that were either ignored or improperly addressed:

1) A framework for measuring the value gained by customers and lost by Edison from the insurance policy customers in Michigan have to return to regulated rates.

Line No.

2) An analysis of whether a transition charge that is zero or negative and is not flexible with respect to future market conditions meets policy principles of efficiency and equity in light of the high degree of long-term volatility of electric power prices.

3) A review of various components of Mr. Seiple's valuation approach including tax write-ups, data problems, discount rates and other factors.

4) A critique of the modeling methods, assumptions, and data used by Mr. Seiple to forecast future electricity prices.

5) An evaluation of whether a "comparable asset sales" approach can be used in valuing Edison's stranded investment where information is derived from the divestitures of generating assets that have occurred in other markets with distinctive characteristics.

6) An assessment of the proposals made by Energy Michigan and the Attorney General with respect to transition charges.

Q. Please summarize your conclusions with respect to the recommendations made by witnesses who represent ABATE, the Attorney General and

Line No.

Energy Michigan relative to the proposal made by Detroit Edison?

A. Edison's proposal is more balanced, equitable and efficient than alternative proposals made by ABATE, the Michigan Attorney General and Energy Michigan. Edison's proposed approach includes: (1) incentives for market development through a potential 10% reduction in the generation portion of customer bills; (2) downward or upward adjustments to transition charges that reflect actual market conditions on an incremental basis; (3) adjustments to class-by-class transition charges through the "ETCA" to assure that different customer groups have similar opportunities to achieve savings from use of retail open access service; and (4) use of cost savings from securitization to fund rate reductions, implementation costs and reduced transition charges. This approach developed by Edison has significant and distinct advantages relative to the proposals made by ABATE, Energy Michigan and the Michigan Attorney General for the following reasons:

ABATE: ABATE proposes a negative transition charge that would not change in the future as the market price of energy fluctuates. The negative charge is derived from inappropriate valuation techniques that have many conceptual flaws such as ignoring the option value implicit in the Michigan restructuring plan and use of a forward price analysis that has many data problems and modeling mistakes. The negative transition charge proposed by ABATE is also supported by a

"comparative sales analysis" which ignores valuation implications from purchased power contracts that would have to be in existence after Michigan generating plants would be divested. I have corrected the ABATE valuation analysis to account for data errors, modeling problems, volatility in electricity prices, the value of customer options to switch between bundled rates and market based prices, and contractual obligations that would occur in an asset divestiture. ***The corrected analysis implies that Edison's transition charge should be almost 20 mills/kWh, even using the inappropriate market prices projected by Mr. Seiple.*** Because of significant valuation mistakes made by witnesses who represent ABATE, adoption by the Commission of the proposed negative transition charge would be highly inequitable to Edison and it would be administratively unworkable.

Energy Michigan: Energy Michigan would adjust transition charges through comparing generation costs with market prices on an aggregate company-wide. This differs from Edison's proposal that adjusts transition charges on an incremental basis through measuring financial impacts arising from customers who select retail open access service. By using aggregate company-wide costs rather than incremental costs in computing transition charges, the Energy Michigan proposal relegates customers who choose regulated service

Line No.

into "second class citizens." His approach would ultimately increase rates to bundled customers while reducing costs to direct access customers. In addition, the proposal would also create an inefficient market through a "preferred" bidder suggestion and his discussion of securitization does not account for the fact that, in Edison's proposal, rate reduction benefits of securitization are already directly incorporated into the economic harm and benefit charge.

Attorney General: The Attorney General witnesses dispute Edison's proposed economic harm/benefit component of the transition charge and they recommend that Edison's Equalization Transition Charge Adjustment not be made. Without truing-up costs and market prices, an equitable transition charge would have to recognize the option value that is provided to customers and is forgone by Edison. If the Attorney General positions were adopted, the transition charge would also have to compensate Edison for distorted incentives that occur because of different generation break-even prices among customer classes.

Q. What is your general analytical approach in reviewing the testimony presented by intevenor witnesses?

A. The fundamental tenet of my testimony is that valuation of assets cannot ignore fixed price contracts and "real" options associated with the assets

Line No.

being valued. Basic principles of financial theory dictate that it is impossible to correctly value assets without also measuring the impacts that fixed price contracts and call or put options have on the cash flow produced by those assets. Examples of the importance of contracts to asset valuation are common in finance. The basic difference in valuation between debt and equity securities is the result of differences in contractual claims on an asset. The value of a traded option is dependent on specific terms of the option contract (the exercise price, time of expiration, ability to exercise). Valuation of electric generation plants that are project financed is highly dependent on a myriad of revenue, expense and financing contracts.

Given the importance of contracts and options in valuation of assets, I analyze valuation methodologies presented by ABATE witnesses in light of the fact that Edison customers will have the right to choose either regulated tariffs or market based rates. My approach quantifies the value to customers from the right to "maintain regulation" and it relies in large part on option price theory. I demonstrate that unless an analysis accounts for Edison obligations – the other side of the customer call option -- stranded costs will be understated.

Q. How is the remainder of your testimony organized?

A. After describing the option for customers to choose regulated generation

service in the next section (section **two**), I discuss the logical flaws associated with a negative transition charge is section **three**. Then, in section **four**, I summarize the impacts of correcting the RDI/ABATE analysis to account for conceptual errors related to option valuation, data problems in representing Edison plants, income taxes, discount rates and other items. In this analysis I do not change the market price assumptions developed by Mr. Seiple even though there are obvious problems with his assumptions, his data and his model that, if corrected, would provide vene more support for my conclusions. Correction for conceptual valuation flaws in Mr. Seiple's analysis implies that his estimate of Edison stranded cost should be ***positive $2.775 billion*** instead of negative $760 million.

In section **five**, I describe how volatility in electricity prices affects policy on transition charges and valuation of assets. I explain why transition charges that are not flexible with respect to varying market conditions can pose significant problems. Section **six** addresses the comparable sales approach presented by Dr. Tabors. Here, I demonstrate that if an asset sale is simulated, then the simulation must incorporate necessary contracts with the new owner to meet Edison's continuing regulated service obligation. This "post transaction" contract would significantly reduce value in an asset sale transaction. Moreover, the contract structure makes the comparable sales data used by Dr. Tabors irrelevant for purposes of Michigan restructuring.

Line No.

In Section **seven** I review the shortcomings in Mr. Seiple's market price modeling involving the structure of his model, the assumptions he makes, and the quality of his data. I describe how his model structure has inappropriate algorithms related to capacity prices, probabilistic modeling of forced outages, reflection of marginal heat rates, start-up costs, minimum run times, spinning reserve, and voltage support. Mr. Seiple assumes that thousands of megawatts of announced new merchant capacity will not be built, he does not consider any new capacity that is not gas-fired even though he projects high natural gas prices, he assumes allowance costs that are far higher than forward price levels, and his reserve margin criteria are arbitrary. Finally, Mr. Seiple uses inconsistent and/or erroneous data on loads, heat rates, plant capacities and many other items.

I discuss problems Mr. Seiple's modeling of the cost structure of Edison plants in section **eight**. Major problems with his analysis include assuming a tax write-up and not including costs that are actually incurred by Edison as reported in the FERC form 1. Corrections to reflect the cost structure of Edison's plants and appropriate tax depreciation reduces the market of Edison plants from $5.7 billion to $3.317 billion. In section **nine** I correct Mr. Seiple's analysis for a mistake he makes in computing the market based cost of capital. By making an inappropriate assumption that

Line No.

debt will never be paid off, he overstates the market value of Edison assets by more than half a billion dollars.

I quantify the value implications of customer options to switch between regulated service and open access service in sections ten, eleven and twelve. In section **ten** I compute the value of the customer option without volatility in electricity prices, in section **eleven** I add volatility in electricity prices to the analysis, and in section **twelve** I describe how non-optimal customer decisions and volatility in regulated rates affects valuation. ***Using a 20% price volatility assumption, the Edison obligation to provide an insurance policy to direct access customers reduces Mr. Seiple's valuation estimate by $1.820 billion.***

I discuss issues other than Mr. Seiple's valuation and Dr. Tabors' valuation in the final two sections of my testimony. In Section **thirteen** I review the proposal made by Energy Michigan. In Section **fourteen** I discuss miscellaneous items related to statements made by the Attorney General witnesses and ABATE witnesses.

Section Two

<u>Customer Options to Return to Bundled Service in the Michigan Restructuring</u>

Line No.

Q. Why do you begin your testimony by describing the customer option to switch back to bundled rates after having selected direct access service?

A. The notion of allowing customers to switch between market pricing and regulated service is established in the recently passed Michigan legislation:

> "To allow and encourage the Michigan public service commission to foster competition in this state in the provision of electric supply ***and*** ***maintain regulation of electric supply for customers who continue to choose supply from incumbent electric utilities***." *(Public Act No. 141 of 2000, Sec. 10(2), emphasis added.)*

This language demonstrates that the principle of customers maintaining the option to retain regulation of electric supply for customers who choose supply from incumbent electric utilities is central to the restructuring plan in Michigan. Mr. Gerard Anderson explains the customer option as follows:

> Electric utilities in Michigan retain the obligation to serve customers within their service territory and their generation assets will be deployed to serve these customers. This provides Michigan customers substantial protection from the possibility of high prices in the future, while providing the opportunity for them to benefit is market prices are lower than regulated rates. (Anderson testimony at page 5.)

The obligation to provide service at regulated rates can be defined as a "call option" that is provided by Edison to Michigan customers because customers have the right -- but not the obligation -- to purchase power at market-based prices with a "strike price" equal to the generation

Line No.

component of bundled rates. While various intevenor witnesses including Dr. Tabors, Mr. Selecky and Mr. Peloquin downplay this feature of restructuring in Michigan, I submit that the contract call option distinguishes Michigan from other states.

Q. Have any witnesses in this case presented "real world" evidence of the right to switch between prices that are derived from regulated rates and prices that are derived from market clearing prices?

A. Yes. The organization Citizens for Power and Reliability ("CPR") presented two witnesses who have attempted to secure power from the market. One of the witnesses, Mr. Bruce Frandsen, who is the Facilities Engineering Manager for Perrigo Company, described how he was able to secure savings from 1998 through 2000 through direct access to market prices. However, he comments that "the current market is one in which alternative suppliers will be find it extremely difficult or impossible" to compete with tariffs of the incumbent utility company (Frandsen testimony at page 9.) Therefore, he explains that his company "will be forced to return to normal tariff service." (Frandsen testimony at page 7.)

Mr. Frandsen is clearly a leader in managing energy and his efforts to reduce costs should be commended. However, when market driven energy costs rise, even the best energy manager cannot reduce electric bills through making market purchases. Most of us would no doubt be

Line
No.

happier if energy costs were low, but, if market prices for energy increase, it is nice to have the option to have a cap on costs. In fact, Mr. Frandsen's story effectively demonstrates the value of the option to switch between the direct assess program and tariff service. If Perrigo did not have the option to return to bundled service when market prices increased last year, I suggest that he would probably have been even more upset.

Q. Has the option to switch between the direct access program and tariff rates benefited Perrigo?

A. Yes, I think it has. The table below demonstrates my understanding of Mr. Frandsen's experience in three different time periods. This shows how Perrigo has been able to save money when electricity prices were relatively low and how his company also avoided exposure to relatively high market prices through exercising his option to switch to tariff rates when energy costs increased.

	Option Selected: Tariff Rates or Direct Access	Savings Relative to Tariff Rates Achieved From Accessing Market	Costs Incurred from Being Exposed to Market Prices when Prices Exceed Tariff Rates
Period 1: April 1998 through December 2000	Direct Access	$25,000-$30,000 per month	None
Period 2: January 2001 through December 2001	Part Open Access/Part Tariff	$8,000 - $9,000 per month	None
Period 3: Post December 2001	Tariff	None	None

Line No.

Given the efforts made by CPR witnesses Ms. Kalil and Mr. Frandsen to reduce their energy costs, their disappointment is understandable. However, if they did not have the option to return to cost based (rates such as is the case for customers in New England), or if all generation costs were tied to market prices (soon to be the case in my home state of Illinois), or if there were no possibility to obtain market based rates (the situation in Kentucky), I suspect these two professionals would be even more frustrated.

Section Three

Logic of a Negative Transition Charge Given the Customer Options to Receive Regulated Service from Incumbent Utility Companies

Q. What is ABATE's recommendation with respect to current and future transition charges?

A. ABATE proposes to give customers who participate in open access a reduction on their electric bills of $4.18/MWH and this credit apparently would not be adjusted for future changes in the market price of electricity. According to ABATE's witness Mr. Selecky: "the Commission should establish a net stranded cost credit or negative surcharge." (Selecky testimony at page 2.) He elaborates that: "DECo's net stranded benefit credit should be larger than DECo's proposed securitization surcharge"

(Selecky testimony at page 10.)

Q. Is a negative or zero transition charge that does not change for a long period of time logical in Michigan?

A. No. A negative or zero transition charge[1] that is fixed at the same level for a number of future years does not lead to efficient market development and it is unfair to Edison given the customer call option. A negative charge is inequitable because not only can Edison not recover stranded investment, but the Company must also pay customers to leave its system at precisely those times when financial exposure to stranded investment exits. To illustrate why a negative transition charge is both illogical and unfair to Edison, I separately consider the Company's stranded investment exposure during low market price and high market price periods.

Relatively more customers will choose the option to secure power from market based prices when a ***low*** market price environment results in electric bills below bills those that exist using regulated tariffs. During these low market price time periods, Edison incurs stranded investment. Yet if the transition charge is negative, Edison can obviously not recover its stranded investment. Indeed, if market prices remain low, Edison pays

[1] For purposes of this section a negative transition charge is assumed to be after securitization charges. For example, if the net economic benefit is $2/MWh and the securitization charge is $5/MWh, the transition charge is assumed to be positive for purposes of this discussion.

Line No.

customers to leave ***and*** the Company does not recover any of the positive stranded investment it incurs.

Now consider time periods when market based prices are high enough to result in costs that are greater than bills which occur from regulated tariffs. In this situation, as described by Mr. Bruce Frandsen of Perrigo Company, customers will have no economic incentive to purchase from the market. This means that Edison cannot “make back” or "monetize" its losses that arose from low market price periods through making a lot of money by selling the “freed-up” energy from customers who have left the system. In sum, during low price periods, stranded investment exposure exists and in high market price periods Edison cannot offset the amounts it lost when prices were low.

Q. Can you illustrate these effects with an example?

A. Yes. In the table below I assume two time periods, one time period in which market prices are above the generation component of bundled rates and another period when market prices are below the generation component of bundled rates. I also assume that all customers make rational economic choices with respect to use of regulated service from Edison at bundled rates or retail open access service at market based rates.

Inability to Recover Stranded Cost with Negative Transition Charge and Customer Option

Time Period	Financial Exposure to Positive Stranded Investment from Market Prices below Embedded Cost	Recovery of Stranded Investment from Realizing Above Prices Above Embedded Costs	Edison Losses from Paying Negative Tranistion Charges
Low Market Price Period when Market Prices are below the Generation Portion of Rate in Bundled Tariffs	Edison experiences losses measured by the formula: (Market Price - Generation Component of Bundled Rates) x Direct Access Energy	None	Edison experiences added losses from paying a negative transition charge measured by the formula: (Negative Transision Charge) x Direct Access Energy
High Market Price Period when Market Prices are above Generation Portion of Rate in Bundled Tariffs	None	None	None

In the above table, Edison only experiences financial losses and does not realize any offsetting gains that can be "netted" against the losses. At those times when prices are low, financial exposure exists from stranded costs as calculated by the difference between market prices and embedded costs as well as the negative transition charges paid out to customers. On the other hand, when the market price is high, Edison has no ability to recover or "monetize" the stranded cost because customers are exercising their option to take service at cost based rates from the incumbent utility company.

Section Four

Summary of Correction to Mr. Seiple's Plant Valuations to Reflect Customer Options to Take service From the Incumbent Utility at Regulated

Line No.

Rates and Other Conceptual Flaws

Q. Are the valuation approaches applied by ABATE witnesses Mr. Seiple and Dr. Tabors appropriate for analyzing the relationship of market value to the net book value of generation assets in the context of specific characteristics of Michigan's electric restructuring program?

A. No. Analytical approaches that measure stranded investment using either (1) discounted cash flow over the lifetime all of Edison's generating units as recommended by Mr. Seiple, or (2) valuation data on supposedly comparable asset sales transactions as recommended by Dr. Tabors, ignore the customer call option. As a result of this and other conceptual problems, their results are very biased. In this section I demonstrate how correction of defects in Mr. Seiple's valuation analysis affects his conclusions as to the level of Edison's stranded investment. In Section Six below I elaborate on problems with the comparable sales approach.

Q. Given the generation portion of Edison's bundled rate is about 5.0 cents per kWh and RDI estimates 2002 market prices to be 3.0 cents per kWh, is ABATE's negative stranded investment a reasonable conclusion?

A. It is certainly not intuitive. From the exhibits of Mr. Edward Falletich, I have computed a weighted average break-even price of 5.03 cents per kWh without securitization charges. This number is simply the weighted average break-even price without deductions for securitization using the

Line No.

year 2000 data on Exhibit ELF-1, page 1 adjusted for losses.

The average retail price in 2000 shown on Mr. Falletich's exhibit is my starting point for computing the generation price. From that number, I subtract transmission and distribution costs and nuclear decommissioning. I then compute the weighted average generation portion of customer bills through multiplying the class by class number by the level of sales. Once a weighted average rate of 5.394 cents per kWh is computed on a sales basis, I convert the number to an output basis through including a loss rate of 7.23%. I refer to the 5.03 cents per kWh number as the generation component of bundled rates. In contrast to this regulated price, Mr. Seiple presents a generation price of 3.047 cents per kWh in the year 2002 on his exhibit CDS-4.

Since the generation component of bundled rates is 66% higher than Mr. Seiple's market clearing price (5 cents versus 3 cents), one would think that Edison would have positive stranded investment. The fact that Mr. Seiple instead comes up with a negative figure of $760 million for stranded investment can possibly be explained in one of two ways. The first possibility is that Mr. Seiple's calculation of generation cost is completely inconsistent with Mr. Falletich's break-even price. The second possible explanation is that there are large reductions over time in year to year generation costs resulting from Mr. Seiple's analysis.

Line No.

Given intuitive problems with the market prices versus regulated rate disparity and negative stranded investment, I have attempted to reconcile Mr. Seiple's data with actual cost data included in Edison's FERC Form 1 for the year 2000. This process demonstrates that Mr. Seiple's negative stranded investment comes from (1) mechanical problems in Mr. Seiple's analysis with respect to income tax deductions, measurement of Edison's generating cost and modeling of capacity factors for Edison plants; (2) Mr. Seiple's assumption that customers will pay market prices above the generation portion of bundled rates in future years; and (3) Mr. Seiple's cost of capital assumptions.

Q. Are the break-even prices presented by Mr. Falletich similar to generation costs that can be derived from Edison's FERC Form 1?

A. Yes, they are. I have computed the approximate generation cost and production cost from information presented in Edison's FERC Form 1 for the calendar year 2000. In developing the analysis of actual costs, I first computed the rate of return actually earned by Edison and confirmed that the Company earned a return on equity of approximately 11%. Next, I allocated expenses, net plant, deferred taxes and other items on the basis of data in the FERC Form 1 and computed Edison's actual production cost to be 4.90 cents per kWh in 2000. Without purchased power, the generation component of Edison's production cost was 4.66 cents per

kWh. I emphasize that my computations are derived from public data and are not intended to reflect cost allocations that are appropriate for unbundling rates.

Since the data presented by Mr. Falletich is consistent with both an return on equity of 11% and cost data in Edison's FERC Form 1, the question is whether numbers implicit in Mr. Seiple's analysis also approximates the 4.7 cents per kWh number. I demonstrate below that the generation cost implicit in Mr. Seiple's analysis is below 4 cents per kWh implying that his analysis is not consistent with actual Edison data. This understatement of Edison costs per kWh is a significant part of the reason for the counterintuitive results in his analysis. The table below compares costs from Mr. Seiple's analysis with actual Edison costs:

Comparison of RDI and Actual Generation Costs		
($ 000's for the year 2000)		
	FERC Form 1	RDI
Plant by Plant Fuel	649,786.89	876,359.77
Non-Fuel O&M	297,928.80	288,156.23
A&G and Other	367,829.15	208,340.00
Depreciation	397,941.13	283,804.73
General Taxes	163,267.16	93,954.00
Return on Net Plant	451,909.42	445,068.74
Total	2,328,662.55	2,195,683.48
Generation (MWH)	49,985,563	55,447,000
Cost/MWH	**$ 46.59**	**$ 39.60**
RDI as Percent of Actual Cost		85.00%

Q. How can the discounted cash flow approach applied by Mr. Seiple be

Line No.

reconciled with his annual projections of market clearing prices and his forecasts of the generation component of bundled rates?

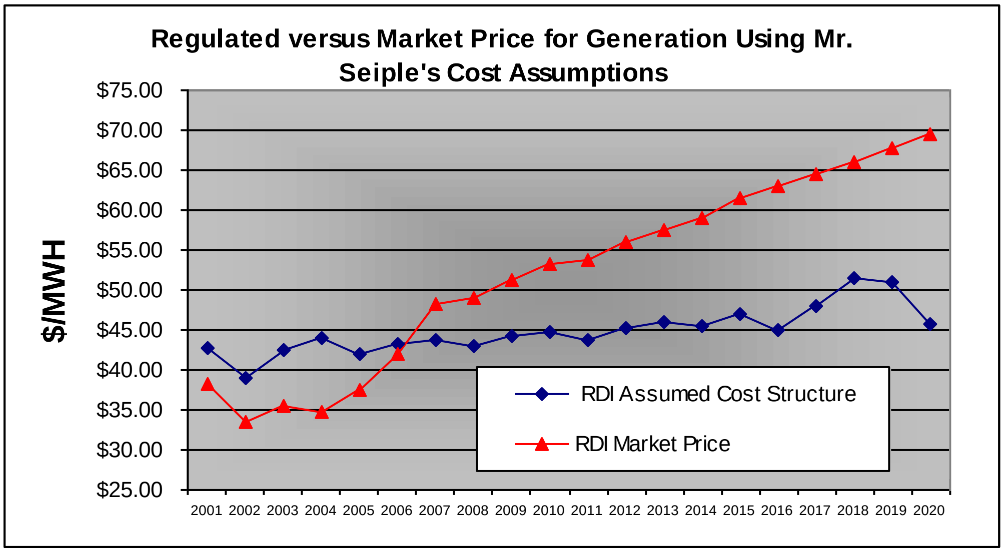
A. In applying the discounted cash flow approach to stranded investment, Mr. Seiple computes the present value of cash flows that Edison's assets can realize at his market clearing price forecasts and his cost assumptions. This computation can be referred to as the market based valuation. However, in computing value of assets Edison realizes from regulated rates, Mr. Seiple does not perform a cash flow analysis. Instead of computing free cash flows Edison could realize from price levels set at the generation portion bundled rates, he simply assumes that the present value of this cash flow stream equates to book value. Using Edison's cost of capital to compute its earnings an discounting cash flow from the earnings at the allowed rate of return means that the annual generation component of bundled rates can be derived from Mr. Seiple's analysis. If this is done, Mr. Seiple's measurement of negative stranded investment from computing one cash flow stream and comparing that stream to book value can also be computed as the difference in the present value of two cash flow streams. These two cash flows streams are then a market based cash flow stream and a regulated cash flow stream.

Using data provided by Mr. Seiple in exhibit CDS-11, I have computed the two separate cash flow streams. The regulated cash flow stream assumes straight-line depreciation, and a capital structure of 50% debt, 50% equity

and a return on equity of 11%. As I explained above, the present value of cash flows from the generation portion of bundled rates equates to the book value of the plants.

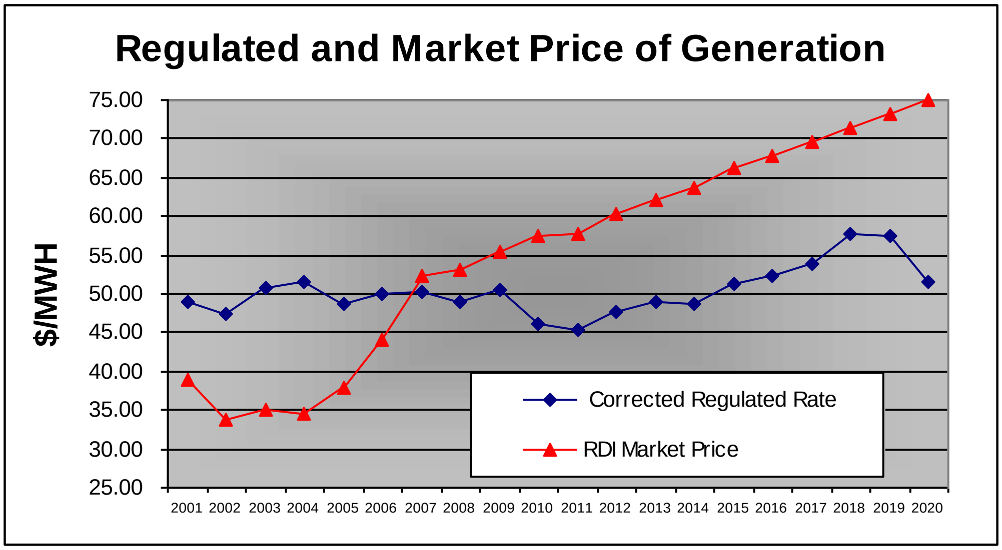
Q. After the annual level of free cash flows from the generation component of bundled rates is established, how can the aggregate annual price levels in Mr. Seiple's analysis be determined?

A. Annual free cash flows are defined in either the market price cash flow stream or the regulated cash flow stream by a formula where costs are subtracted from revenues. The formula can be re-computed from the "bottom-up" to derive implied regulated rates. Applying this process to the cash flow streams shown above yields generation price assumptions shown in the graph below:



Q. Why is the generation portion of regulated prices in Mr. Seiple's analysis significantly lower than the generation component of bundled rates presented in Mr. Falletich's testimony and significantly lower than your analysis of FERC Form 1 data?

A. The reasons are conceptual flaws in Mr. Seiple's analysis with respect to assumed tax write-ups, overstatement of capacity factors on old coal fired plants and ignoring actual data. Correction of Mr. Seiple's analysis for these factors results in a price pattern shown below:



Q. What implicit assumption does Mr. Seiple make in his discounted cash flow analysis with respect to customer exposure to market prices?

A. Mr. Seiple assumes that valuation must be based exclusively on either regulated prices or from market based prices. This method does not allow for the possibility that during some time periods an asset may earn cash flows from market rates and during other periods the asset generates cash flows from regulated rates. The ability of customers to switch between regulated rates and market prices is inconsistent with the basic presumption of Mr. Seiple's discount cash flow approach.

Q. How is the discounted cash flow analysis affected by the right customers have to return to regulated service in Michigan?

A. If customers have a choice as to acceptance of market prices or the

generation portion of bundled rates, one would expect customers to act in an economically rational manner and to select the lowest cost alternative in each time period. When the generation portion of regulated rates is below the market price, bundled rates will be chosen. Alternatively, when the market price is below the generation portion of bundled rates, customers will select market based pricing. This means that for stranded investment purposes, cash flows from the area where market prices are higher than embedded cost cannot exist. This cash flow cannot be realized by Edison because customers will select the option to return to regulated rates when regulated rates are less than market based prices

In many respects, the option customers have to switch service between regulated rates and market prices is like a call option on a stock. Furthermore, if one believes Mr. Seiple's market price forecasts, the customer option is "in the money" when the market prices are above the regulated generation prices. ("In the money" means that the price of a call option is below the strike price.) While the customer option to switch service is analogous to a call option on a stock, unlike stock options that can be exercised only one time, the customer option can be exercised multiple different times.

Q. Elaborate on biases that arise from application of the discounted cash flow method proposed by Mr. Seiple.

Line
No.

A. The amount of bias in stranded investment calculations from inappropriately assuming that customers will not make rational choices depends on the assumed level of market price in the valuation analysis. The higher the market price, the more the impact of this bias from ignoring the value of the option. Even without consideration of volatility in market prices, in the relatively high RDI market clearing price scenario, the inappropriate assumption that customers will not select the most economically beneficial rate alternative lowers Edison's stranded investment by a wide margin. As I stated above, if Mr. Seiple's market price scenario is assumed, one could say that the customer's option to switch to bundled rates is "in the money." The value of an in-the-money option is higher than an out-of-the money option, other things being equal.

Using Mr. Seiple's market price scenario, the stranded investment is increased by $1.8 billion correcting the inappropriate assumption that customers do not rationally switch to regulated rates. On the other hand, if a lower market price were assumed, measurement of stranded investment using the discounted cash flow model would be higher, and the assumption that "netting" from irrational behavior would have less of an impact.

Q. If Mr. Seiple's market price assumptions and his operating cost assumptions are accepted, how do conceptual problems affect

Line No.

measurement of Edison's stranded investment?

A. I have computed the value of Edison's stranded investment using Mr. Seiple's market price forecasts and his assumptions on Edison's plant operating costs. Before presenting this analysis, I emphasize that by using Mr. Seiple's numbers, I in no way mean to imply that I agree with his assumptions, his methodology or the data he uses to project market prices. Indeed, I have found major flaws in Mr. Seiple's analysis, which imply the forecasts are inappropriate for use in this proceeding.

Applying Mr. Seiple's market price assumptions, the table below summarizes how correction of conceptual flaws affect measurement of Edison's stranded investment. Mr. Seiple estimates Detroit Edison stranded investment to be negative $760 million. However, when his analysis is corrected for fundamental mechanical valuation flaws, the stranded investment becomes ***positive*** $2.775 billion as demonstrated in the two tables below:

Stranded Cost Using RDI Electricity Price Projections and Operating Costs without Customer Option				
($ 000's)				
	Value at 12/31/00	Market Value of Assets - RDI	Market Value of Assets Corrected for Tax Depreciation	Market Value of Assets Corrected for Tax Depreciation and Discount Rate
Steam	2,270,674	5,563,648	4,641,261	3,964,357
Nuclear	2,333,000			
Pumped Storage	94,415	94,695	78,538	125,275
Gas Turbines	200,339	42,978	82,706	85,041
Total	4,898,428	5,701,320	4,802,505	4,174,673
Value of Power Contracts per RDI		(44,000)	(44,000)	(44,000)
Market Value of Assets After Contracts		5,657,320	4,758,505	4,130,673

Corrected Stranded Cost Using RDI Electricity Price Projections				
($ 000's)				
	Book Value at 12/31/00	**Deferred Tax at 12/31/00**	**Net After Deferred Tax**	**Market Value of Assets**
Steam	$ 2,382,678	$ 528,228	$ 1,854,451	$ 2,967,502
Nuclear	$ 2,327,689	$ 822,120	$ 1,505,568	$ (432,843)
Pumped Storage	$ 95,933		$ 95,933	$ 125,275
Other Production	$ 199,569		$ 199,569	$ 85,041
Total	$ 5,005,868	$ 1,350,348	$ 3,655,521	$ 2,744,975
Value of Power Contracts per RDI				$ (44,000)
Value of Customer Option				$ (1,820,139)
Total Market Value				$ 880,836
Embedded Cost				$ 3,655,521
Total After Tax Stranded Cost				**$ 2,774,685**
Generation (MWH)				49,985,563
Loss Factor				7.23%
Sales Basis (MWH)				46,369,267
PV Factor for 7 Years				5.01
Levelized After Tax Requirement				$ 553,752
Levelized Pre-Tax Requirement				$ 878,971
Required Transition Charge ($/MWH)				**$ 18.96**

The above tables illustrate that the analytical flaws present in discounted cash flow models are not trivial details but dramatically impact the valuation of generating plants.

Q. Please describe the magnitude of the different conceptual flaws in Mr. Seiple's valuation of Edison's generating assets.

A. In the table below I show separate components of my correction to Mr. Seiple's analysis. The corrections include incorporation of actual costs as reported in Edison's FERC Form 1, elimination of tax write-ups, reflection of realistic debt maturity terms, use of reasonable inflation rates and valuation of the customer options to return to regulated service from the incumbent utility company.

Valuation of Edison Generating Assets Assuming RDI Market Prices

($ 000's)

	Dollar Value of Edison Plants	Reduction in Value from Correction	Percent Reduction in Value from Correction	Cumulative Percent Reduction in Value
ABATE Testimony	$ 5,701,320			
Corrected Tax Depreciation	$ 4,802,505	$ 898,815	15.77%	15.77%
Discount Rate Correction	$ 4,174,673	$ 627,831	11.01%	26.78%
Corrected Cost Data	$ 2,744,975	$ 1,429,698	25.08%	51.85%
Including Option, No Volatility	$ 1,177,993	$ 1,566,982	27.48%	79.34%
Including Option, 10% Volatility	$ 1,084,723	$ 93,270	1.64%	80.97%
Including Option, 20% Volatility	$ 924,836	$ 159,887	2.80%	83.78%
Including Option, 30% Volatility	$ 555,495	$ 369,341	6.48%	90.26%

Section Five

Line No.

Volatility of Electricity Prices and Valuation of Electric Generating Plants

Q. Does Dr. Tabors recognize the importance of volatility in valuation of generating assets?

A. He appears to. Dr. Tabors testifies:

> "valuations using a production cost model typically do not capture the volatility in wholesale markets that arise from uncertainty, and thus fail to capture the optionality value of generating units….During the past two years volatility has been steadily increasing in ECAR…" (Tabors testimony at page 13.)

Dr. Tabors is correct that volatility impacts the value of generating assets. However, because the Michigan restructuring plan implies that Edison must **provide** a call option to customers, volatility in electricity prices increases value to customers and it diminishes the value of assets to Edison. Dr. Tabors' statement regarding volatility in electricity prices also implies that setting a fixed transition charge which is inflexible with respect to future market conditions may not be good public policy. Yet a transition charge that is invariant with changing market conditions is precisely what ABATE proposes.

Q. Contrast the way Edison's transition charge proposal works with the way ABATE's proposal works when power prices are volatile.

A. In Edison's proposal the transition charge varies when power prices change, while ABATE would fix transition charges at levels derived from

Line No.

asset valuations estimated by their consultants. ABATE witness Selecky suggests that no recognition should be made for future changes in the market price of power. He testifies "[i]t is critical that the Commission examine DECo's cost and determine which costs are stranded, and not rely on lost revenue calculations." (Selecky testimony at page 15.) Mr. Selecky later testifies that "stable estimates of net stranded cost are imperative." (Selecky testimony at page 17.)

Q. Has there been significant volatility in RDI estimates of generating plant market value?

A. Yes. The benefits of allowing flexibility in transition charges with respect to volatility in plant valuation are illustrated by reviewing previous valuations made by Mr. Seiple's firm. A previous estimate of Edison's stranded investment made by RDI suggested that generating assets had a market value of $2.430 billion. In the current study, Edison's market value has supposedly increased by 123% to $5.432 billion. (This $5.432 billion value differs from the $5.7 billion value presented in Mr. Seiple's testimony because I included the negative market value of Fermi in order to be consistent with the earlier estimate.) If the market value of Edison's assets can in fact change by this magnitude, regulatory policy should certainly account for volatility.

Another example of volatility in Mr. Seiple's valuation is demonstrated by

Line No.

his valuation analysis of fossil-fired plants originally owned by Commonwealth Edison Company. Mr. Seiple testifies that he "led the valuation process for a potential buyer of more than 4,000 MW of predominately coal-fired generation in the Midwest." Dr. Tabors shows that the actual value in this transaction was $4.423 billion implying that the non-peaking plants sold for $530/kW. (The value of $530/kW is 24% below Mr. Seiple's $698/kW estimate of the value of Detroit Edison's steam plants.) The extreme volatility in the RDI valuations is demonstrated by an earlier analysis that Mr. Seiple presented regarding the value of Commonwealth Edison generating plants. Just a year or two before the Commonwealth Edison plants were sold, Mr. Seiple made a presentation to a legislative committee in Illinois where he estimated the value of Commonwealth Edison steam plants to be only $81/kW or $676 million. This number suggests an increase in value of more than 500%.

Section Six

<u>Use of the "Sales of Comparable Units" Approach to Valuing Assets Recommended by Dr. Tabors</u>

Q. Is Dr. Tabors' "comparable sales" approach is an accurate method for establishing stranded costs in Michigan?

A. No. Dr. Tabors testifies that "the most accurate method of establishing the

net stranded costs of a utility's generating capacity would be through the divestiture, or the sale of those units." He also states that "a valuation of utility generating units based on a cash flow approach will ***always*** under-estimate the market value of generating units, even if all input and modeling assumptions are reasonable" (Tabors testimony at page 4, emphasis added). I disagree with both of these statements. First of all, divestiture of generating assets combined with fixed price purchased power contracts provides the Commission with no useful valuation information. Secondly, selling of assets does not necessarily add value to customers. To the contrary, divestiture without post-transaction contracts can significantly increase costs to customers and produce very negative impacts on the financial position of utility companies.

Q. How do results of the "comparable sales" approach compare with results produced by Mr. Seiple's discounted cash flow method?

A. The approach of simulating the market value of Edison's plants from prices that have occurred in other divestiture transactions is even more biased than the discounted cash flow approach. If generating plants are sold, Edison cannot realistically offer customers an option to switch back to regulated rates unless it agrees to complex contracts with the asset purchaser that have capped prices aligned with regulated rates. The divestiture approach is also flawed because it does not account for the tax liability Edison incurs when assets are sold. Instead, the divestiture

method inflates market valuation of assets because of the fact that new owners write-up assets for tax purposes.

Q. If Edison divested its generating assets, what possible scenarios could occur after the plant sale with respect the relationship between Edison and the new owner of its plants?

A. If Edison divested its generating units, there are four general alternatives with respect to purchased power contracts and customer exposure to market based prices after the transaction has been completed:

Post-transaction Scenario One: Edison could agree to a fixed price purchased power contract with the new owner of its generating assets so that the obligation to cap rates for customers who choose to retain supply from incumbent utilities could be met without making market purchases;

Post-transaction Scenario Two: Edison could meet its obligation to provide power to customers at fixed prices through making its shareholders incur the risk of purchasing power at high market prices in order to cover the price cap obligations;

Post-transaction Scenario Three: Edison could attempt to define the term "maintain regulation of electric supply for customers who

choose supply from incumbent utilities" as providing physical kilowatts to customers but expose all customers to market prices;

Post-transaction Scenario Four: Edison could develop a complex contract structure with the new owner whereby an agreement between the new owner and Edison would have an embedded option that mimics the obligation to cap prices at regulated rates.

Q. Which of these four post-transaction alternatives is appropriate to use in valuing Edison's assets?

A. As I explain below, the only way to appropriately value Edison's generating assets is to assume that the purchaser must enter into a contract with a cap on prices as described in the post transaction alternative number four. Performing a valuation assuming any of the other three alternatives is inconsistent with the premise of Michigan restructuring that customers can retain "regulated" supply from the incumbent utility company at capped rates. Therefore, when Dr. Tabors testifies that "methodologies used in other states to determine stranded costs are applicable in Michigan," he is mistaken. As I explained above, valuation must reflect the obligations associated with an asset.

Q. Which of these four post-transaction alternatives does Mr. Selecky imply is appropriate to use in valuing Edison's assets?

Line No.

A. Mr. Selecky suggests that the obligation to provide electric supply to customers at capped rates should not be considered in the valuation of Edison's assets. He testifies:

> A proper definition of net stranded costs should be based on the valuation the market would give to utility assets. This asset-based approach recognizes that it is the value of an asset in competitive markets that is the ultimate determinant of utility strandable costs, not the amount of utility revenues lost because of a switch in generation suppliers." (Selecky, page 14).

This means, in turn, that Mr. Selecky's asset valuation would assume that all customers are exposed to market based prices as described in post-transaction alternative number three.

Q. Which of these post-transaction alternatives does Dr. Tabors imply should be the basis for valuing assets?

A. Dr. Tabors implies that valuation of assets is not significantly affected by obligations that arise after the assets have been sold.[2] At one point he suggests Edison should bear financial consequences of market purchases (post-transaction scenario number 2) and enter into long-term contracts (post-transaction scenario number 1): "…if it [Edison] decides to sell some of its generating assets and to meet its retail service obligation through a portfolio of its remaining capacity and bilateral contracts, it again must bear the financial consequences." (Tabors testimony at page 16.)

[2] For example, he compares transactions with and without contracts in his exhibits.

Line No.

Later he emphasizes use of long-term contracts to meet obligations associated with the Michigan program. (Tabors testimony at page 17.) As I stated earlier, it is an elementary proposition in finance that if contracts are associated with assets, valuation must account for these contracts.

Q. Explain how plants should be valued if the first post-transaction alternative occurs whereby a fixed price long-term contract is established when assets are sold?

A. In this scenario, Edison's asset value would be driven in large part by the price level of the purchased power contract. The higher the contract price, the higher the asset value. The influence of long-term contract prices on the valuation of generating assets is demonstrated by one of the transactions that Dr. Tabors includes on his exhibit RDT-2. In that exhibit he presents data on the sales of two coal plants from Unicom to Southern Company and Dominion (the Stateline and Kincaid plants). Dr. Tabors' exhibit illustrates that these two plants were sold at a price equal to their book value. The two plants were sold precisely at book value only because of the existence of a long term fixed price purchased power contract which had cost of service based price levels. If the contract had a different price, the transaction would have had a different value.

Q. If a fixed price contract is part of a divestiture agreement, why does the comparable sale method not provide useful information for purposes of

evaluating the relationship of market value to book value of generating assets for Detroit Edison?

A. To illustrate the circularity and the fallacy of the Dr. Tabors' testimony, consider a situation where Edison sells its plants, but it also establishes a long-term fixed price purchased power contract with the buyer priced at a rate that will match the generation portion of bundled rates or embedded cost. In this case, because of price levels in the long-term contract, the buyer would pay Edison the book value of the asset. Then there would be no stranded cost associated with the assets. However, stranded cost analysis would now have to be performed on the long-term fixed price contract, because price levels in the contract would obviously differ from market-based prices. Furthermore, in computing stranded investment on the long-term fixed price contract, one would have to recognize that during periods when market prices are above levels in the contract, Edison cannot "monetize" losses that occur from periods in which market prices are lower than the contract prices.

Q. Please explain how Edison's stranded investment would be valued if the <u>second</u> post-transaction scenario occurs whereby Edison shareholders take the risk of providing service at capped prices after an asset divestiture?

A. If Edison must retain the obligation to provide service at capped rates after it sells its assets, the asset sale transaction really encompasses two

Line No.

different economic transactions:

1) Edison sells the assets and the company must purchase power to meet obligations to regulated customers at market based prices; and

2) Edison implicitly incurs obligations associated with a call option where the strike price is the capped regulated price level.

Unless Edison is compensated for both components of the transaction, the asset sale price will not be useful in measuring stranded investment.

A number of parties have suggested that their proposals would avoid the negative effects of deregulation in California and I have tried to avoid this temptation. However, the bankruptcy of Pacific Gas and Electric and the financial disasters of Southern California Edison is the direct result of obligations from the type of call option described in second bullet point above. Dr. Tabors presents only one California asset sale transaction with a price of $189/kW (his exhibit does not show Southern Cal Ed or PG&E sales to Duke energy). With hindsight, I doubt that many people would suggest asset sale transactions in the range of $200/kW have been good for California customers. Instead, we now know that significant financial distress arose from the obligation to provide service at capped prices and that the obligation to provide service at capped rates should have been

Line No.

accounted for by both company management and regulators when the policy to divest assets was being considered.

Q. What are the implications on customers if the third post-transaction alternative occurs whereby Edison customers lose the right to capped prices after an asset divestiture?

A. If an asset divestiture policy is implemented where all customers – both retail open access customers and customers who choose to retain service from the incumbent utility company - are subject to market price volatility, many customers will be worse off.[3] In the case of a divestiture with no power contracts subsequent to the transactions and where Edison does not have an obligation to provide service at regulated rates, customers lose their insurance policy to hedge volatile market prices through returning to bundled rates.

The case where customers lose the right to regulated rates at cost based prices is the only scenario in which asset valuation from divestiture without contracts could have any relevance. Edison could be a provider of last resort, but the provision of power would be at market prices that are not capped at levels that would occur had prices remained regulated. Dr. Tabors appears to advocate this position in his testimony when he states

[3] This is similar to a "virtual divestiture" described by Dr. Tabors where Edison charges all customers rates based on market prices.

Line No.

"there are no sections in PA 141 that specify the resources that either utility should use to meet that retail service obligation." Dr. Tabors' statement implies that the retail service obligation could be met with market purchases. In New England, where this type of policy has been adopted, some industrial customers have been exposed to 50% rate increases and some residential customers are paying 17 cents per kWh. In other situations, such as in Massachusetts, standard offer rates are based on two-year contracts, but when the contracts are renewed, and when all customers are exposed to "default service," the rate increases will be very significant.

Q. Please explain how Edison's plants would be valued under the <u>fourth</u> post-transaction. That is, a contract structure with the asset purchaser that mimics Edison's obligation to cap prices at regulated rates.

A. In this post-transaction scenario, a purchase power contract with the new owner would be tailored to Edison obligations associated with the Michigan restructuring program. The post-transaction contract would be designed so that if prices are below the regulated cap level, the new owner receives the market price. However, if market prices exceed the cap, a financial arrangement would occur so Edison could provide power to customers at rates that would be present had the company continued to own its generating assets. In this contract structure, the customer

obligations could be met (alleviating the problems with alternative 3), Edison shareholders would not be exposed in the manner in which California utilities have paid for the exercise of the call option (alleviating problems with alternative 2) and the assets would reflect market prices (alleviating problems with option 1).

In valuing assets with this type of contract, the purchaser would recognize that he is purchasing an asset and at the same time selling a call option. The purchaser would have to value the call option in valuing the assets. My adjustments to Mr. Seiple's analysis described below do precisely this. My analysis demonstrates that selling the call option would have a very significant negative effect on valuation.

Q. Does Dr. Tabors account for taxes that would be paid by utility companies on the gain on the sale of plants?

A. No. Dr. Tabors states that "utilities have used the gains in excess of net book value from such sales to offset their stranded cost." This gain must be on an after-tax basis – funds used to pay taxes cannot also be used to reduce stranded investment. Similarly, after tax transition charges must recover after-tax stranded investment obligations. After consideration of tax liabilities incurred on Dr. Tabor's hypothetical transaction, the stranded investment exposure would be reduced by a significant amount because there is little tax basis associated with Edison's steam plants.

Line No.

Q. Comment on the specific comparable sales transaction data used by Dr. Tabors in his comparable transaction approach?

A. The overwhelming flaw in Dr. Tabor's comparable sales analysis is the conceptual problem with properly reflecting obligations that arise after the transaction. This means that all of his data analyses are irrelevant. However, notwithstanding the fundamental flaw in Dr. Tabors' approach, there are also a number of problems with his data analysis. Some of these problems include:

1.) Dr. Tabors' method of selecting companies is arbitrary.

2.) Dr. Tabors' valuation of pumped storage is based on inappropriate markets (New England) where on peak versus off-peak price differentials are affected by the specific market structure in NEPOOL.

3.) Dr. Tabors' does not adjust valuations for plants that have post-transaction purchased power contracts.

4.) Dr. Tabors' does not adjust his analysis for plants with differences in efficiency, operation and maintenance costs, expected lives, and recent capital expenditures.

Section Seven

Line No.

RDI's Market Electricity Market Price Forecast

Q. Please summarize Mr. Seiple's forecast of electricity prices as compared to actual on-peak and off-peak prices at the Cinergy hub?

A. The table below compares Mr. Seiple's forecast of electricity prices to actual market clearing prices. The table demonstrates that Mr. Seiple's prices are far higher than the actual prices and that the discrepancy is highest for off-peak prices. Relative to actual off-peak prices from 1997 through 2000, Mr. Seiple's forecast is more than 50% above the actual price. In making the computation shown in the table, I allocated capacity prices projected by Mr. Seiple to on-peak periods and I use actual prices from data published by Power Markets Week.

Comparison of RDI Price Forecasts with Actual Price Data from Power Markets Week

($/MWH)

	1997	1998	1999	2000	Average	RDI Average Forecast	Percent RDI Above Actual Prices
Cinergy On-Peak	$ 23.64	$ 56.97	$ 51.43	$ 36.43	$ 42.12	$ 44.23	**5.01%**
Cinergy Off-Peak	$ 13.93	$ 13.60	$ 14.48	$ 16.13	$ 14.54	$ 22.19	**52.65%**
Cinergy Wtd Average	$ 18.54	$ 34.20	$ 32.03	$ 25.77	$ 27.63	$ 32.66	**18.17%**
N. ECAR On-Peak	$ 24.89	$ 56.99	$ 44.32	$ 39.19	$ 41.35	$ 44.23	**6.97%**
N. ECAR Off-Peak	$ 14.81	$ 13.60	$ 14.11	$ 16.13	$ 14.66	$ 22.19	**51.33%**
N. ECAR Wtd Average	$ 19.60	$ 34.21	$ 28.46	$ 27.08	$ 27.33	$ 32.66	**19.46%**

Line No.

Q. Are the forecasts of market price developed by Mr. Seiple reasonable to use as a basis for setting transition charges over a long time period?

A. No. I do not agree with Mr. Seiple's statement that “[o]ur market price forecast for Michigan uses the best available data and information and relies on well-established forecasting principles.” To the contrary Mr. Seiple's price forecasts are formed on the basis of inappropriate modeling techniques, biased assumptions, and problematic data sources. For example, he assumes only new merchant capacity with the code “advanced development” or “under construction” in his own database will be built. The amount of added capacity from new merchant plants is a very important assumption in production cost modeling and Mr. Seiple excludes many thousands of megawatts of announced plants in his analysis.

Q. Please describe your understanding of Mr. Seiple's "forecasting principles" as he applies them to projecting electricity prices.

A. Dr. Tabor's testifies that Mr. Seiple's forecasting method uses traditional production cost models:

> the computer models used to simulate the operation of competitive wholesale markets are essentially the same production costs models as are used to simulate the operation of regulated markets. (Tabors testimony at page 10.)

Mr. Seiple adds capacity to the model using “RDI's internally developed

Line No.

capacity price model" that assumes in the long-run new capacity will be built to just maintain a 15% reserve margin.

Energy prices in Mr. Seiple's analysis are computed from a simple supply stack that does not appear to account for ramp rates, minimum run times, heat rate curves, start-up costs or constraints on plants resulting from local voltage support. The energy prices also include costs of emission allowances. Mr. Seiple then seems to add transmission prices in each hour of the analysis -- he states "A 2.50 $/MWH on firm transmission (uplift fee) for transmission within MISO is applied." Capacity prices are simply added to energy prices in Mr. Seiple's analysis even though he recognizes that there is no separate capacity market in ECAR. Capacity prices jump by more than 200% from 2005 to 2007 when the 15% reserve margin criteria drives new capacity additions.

Q. Please describe some of the problems with Mr. Seiple's "forecasting principles" as they apply to his forward price analysis.

A. While I have not been able to inspect Mr. Seiple's entire model, some of the modeling problems that appear from his testimony and exhibits include:

1) Through not modeling incremental heat rates, start-up costs, minimum run times and ramp rates, the off peak prices are

Line No.

overstated in Mr. Seiple's model. This overstatement of off-peak prices is confirmed by comparing his forecast for off-peak prices with actual off-peak prices.

2) In determining capacity prices from the cost of new peaking plants, Mr. Seiple appears to apply a nominal cost of capital to the cost of peaking plants. He then escalates capacity prices at the rate of inflation. This procedure double counts inflation and overstates capacity prices.

3) Mr. Seiple does not discuss how capacity mix is determined when adding capacity to meet his assumed 15% reserve margin. Specifically, Mr. Seiple does not describe his algorithm for meeting required aggregate capacity in an optimal manner. If the new capacity mix is not optimal, projected prices will be higher than had an optimal expansion been assumed.

4) Mr. Seiple does not appear to model forced outages on a probabilistic basis, which has been standard in producing cost models for decades. Problems in modeling of outages may be the reason most of Edison peaking plants have zero capacity factors over the forecast horizon.

Line No.

5) Mr. Seiple's reserve margin criteria are not documented and do not appear to reflect actual customer interruption costs at different levels of customer outage.

6) Mr. Seiple's transmission rates do not reflect marginal costs of physical transmission. This modeling approach overstates marginal energy costs.

Q. Please discuss problems you have found with assumptions Mr. Seiple uses in developing his forecasts of electricity prices.

A. From reading Mr. Seiple’s testimony and exhibits, I have the following concerns with assumptions he has apparently used in making price forecasts:

1). Mr. Seiple assumes that only capacity that is already under construction or is in “advanced development“ according to his NewGen database is included in the model. This low capacity addition assumption significantly affects prices. If more capacity were added, capacity and energy price forecast would decline.

2.) Mr. Seiple asserts that his natural gas forecast developed from "our gas price forecasting model" is below the NYMEX forward prices. However, Mr. Seiple’s forecasts are significantly lower than the

Line
No.

average gas price forecast of ten large independent and integrated oil and gas companies as reported by the firm Randall and Dewey.

3.) In discussing new capacity additions to meet his 15% reserve margin criteria, Mr. Seiple only describes new natural gas fired plants even though he assumes high natural gas prices. By not allowing new coal plants his new capacity mix is not optimal and his prices are overstated.

4.) Mr. Seiple assumes very high prices for emission allowances that are much higher than actual traded prices. This assumption results in overstatement of electricity prices.

5.) Mr. Seiple assumes no improvement in the real cost of new plants and he does not appear to reflect differences between summer and winter capacity of new units. Through not including the added winter capacity, the winter electricity prices are overstated.

Q. Please elaborate on Mr. Seiple's assumptions with respect to new capacity?

A. Mr. Seiple's assumption is demonstrated by new capacity that is assumed to be added in Michigan. In his model, Mr. Seiple assumes new Michigan capacity that is operating under construction or in advanced development

Line No.

amounts to 3,600 MW. I understand that more than 13,000 MW have been announced in Michigan. If more new capacity were added in Mr. Seiple's model, both capacity and energy prices would decline in his analysis.

Q. What data problems have you found in Mr. Seiple's analysis?

A. While I have not had the opportunity to fully review data used in Mr. Seiple's forecast, a number of data problems are apparent through reading his testimony and exhibits. Some of these problems include:

1.) Mr. Seiple does not discuss modeling of interruptible versus firm load in developing his reserve margin criteria;

2.) Mr. Seiple asserts that he uses full load heat rates and that the heat rates are computed "based on a combination of EIA-411 and EIA-860 information." However, the EIA data does not allow computation of reasonable full load heat rates and the EIA data does not allow computation of heat rates for plants in Canada and for non-utility plants;

3.) Mr. Seiple does not mention the relationship between non-utility plants and loads. Many non-utility plants serve load "behind the meter" and if these plants are modeled, so should the added load;

4.) Mr. Seiple uses the same variable operation and maintenance cost per MWH for each plant in a category even though plants have very different characteristics;

5.) Mr. Seiple assumes significant growth in peak load occurred from 1999 to 2000 even though actual loads declined;

6.) Mr. Seiple uses a different forecast for coal prices in ECAR from other regions as acknowledged in the testimony of Mr. Roberts. This causes trading between regions to occur because of data differences rather than from economic differences in supply and demand among different regions; and,

7.) Mr. Seiple does not discuss how scheduled maintenance is optimized with respect to market prices. Without optimization of scheduled maintenance, electricity price forecasts will be overstated.

Q. Given all of these problems with Mr. Seiple's models, have you developed an alternative forward price analysis?

A. No. Mr. Seiple's testimony and exhibits demonstrate the fallacy in establishing long-term policy on electricity prices resulting from a

simplified production cost model. As Dr. Tabor's testifies:

> Long-term forecasting and simulation of energy markets has always been difficult because of uncertainty regarding future market conditions. Simulating the future operation of the wholesale electricity market for twenty years is particularly difficult because this market is still in the early stages of a major transition from regulation to competition. Thus, the market price projections produced by the simulation model are directly related to the assumptions about future market conditions input by the witness into his or her model. (Tabor's testimony at page 11.)

Given the inherent uncertainty associated with electricity price forecasting, I add volatility to Mr. Seiple's analysis rather than developing an alternative price forecast. In the discussion below, I analyze Mr. Seiple's valuations without adjusting the level of his prices. Obviously, if the level of the price forecasts were reduced, Edison's stranded investment exposure would increase.

Section Eight

Correction of Mr. Seiple's Valuation for Assumed Tax Write-ups and Actual Cost Data Reflected in Edison's 2000 FERC Form 1

Q. How did Mr. Seiple model tax depreciation on Edison's plants in computing market value?

A. In determining future cash flow generated from market based prices, Mr.

Line No.

Seiple assumes that all non-nuclear plants will realize tax depreciation on the written-up market value of the plant. Mr. Seiple assumes accelerated depreciation on a 15-year basis is applied to all plants except the Fermi nuclear unit. Since Edison's fossil plants have already been for the most part depreciated for tax purposes, Mr. Seiple's assumption artificially increases value. This assumption "shields" the assets from income tax liability and it increases after tax cash flow used in computing value. For instance, Mr. Seiple's model shows that the Monroe steam plant will experience a depreciation deduction for tax purposes of $233 million in 2002 which is about 34% of the plant's book value.

The assumption of a tax write-up means that the after-tax cash flow earned from market prices is increased relative to the after-tax cash flow Edison would actually earn in a competitive market. The assumption that Edison can somehow write-up the value of its assets or sell assets at a taxable gain without experience a tax liability is wrong.

Q. Wouldn't a purchaser of Edison's assets in fact be able to write-up the assets for tax purposes and realize additional tax depreciation?

A. Yes, they would. But if Edison continues to own its assets, the assumption of added tax depreciation is not appropriate. Therefore, the tax depreciation assumption demonstrates that Mr. Seiple bases his analysis on the assumption that an asset sale will occur.

Line No.

Q. If an asset sale occurred and tax depreciation is computed on the basis of increased value, can stranded cost be computed as the difference between market value and book value?

A. No. If an asset write-up is assumed, Edison would also experience a taxable gain that must be considered in computing stranded cost. Assuming Edison has no tax basis associated with the steam plants, Mr. Seiple's error with respect to tax write-ups reduces measured value of Edison's steam plants by $2.058 billion ($5.563 billion multiplied by the 37 percent income tax rate).

A small tax basis in fact is associated with Detroit Edison's generating plants. This means that income taxes associated with the taxable gain after accounting for the tax basis should be added to stranded cost. Using Mr. Seiple's approach, the tax liability can be computed as:

Tax Liability Arising from Asset Sales Transaction =

Tax Rate x (Plant Market Value – Remaining Tax Basis).

Accounting for the tax basis, the market value reduction of Edison's steam plants for purposes of computing stranded investment is $1.688 billion ($5.56 billion minus $1 billion multiplied by the tax rate).

Line No.

Q. What assumption does Mr. Seiple make with respect to non-fuel operating expenses?

A. Mr. Seiple includes operating and maintenance expenses as well as allocated administrative and general expenses. He then assumes there will be no inflation in these expenses for three years. However, Mr. Seiple does not include return on general plant allocated to production, return on intangible plant allocated to production, other power supply operation and maintenance expenses, deferred debits associated with production, depreciation on general plant allocated to production, or depreciation on intangible plant allocated to production.

Q. What is the basis for Mr. Seiple's assumption regarding operation and maintenance inflation?

A. Mr. Seiple makes an assumption that administrative and general expenses will not increase for three years. He testifies to this assumption as follows:

> "based on our experience working with generators competing in a deregulated market, we have found that competition places substantial downward pressure on such administrative costs." (Seiple testimony at page 19.)

Mr. Seiple's statement is not supported by any empirical analysis included in his testimony or exhibits. An appropriate analysis would compare the productivity of Edison assets to actual financial data from non-utility owned projects.

Line No.

Q. Does Mr. Seiple make a similar assumption with respect to fixed operations and maintenance expenses?

A. Yes. While Mr. Seiple does not discuss inflation in fixed operation and maintenance expenses in his direct testimony, on page 3 of his exhibit CDS-6 he states:

> "RDI assumed that fixed O&M costs would not increase between 1999 and 2003 in current dollar terms. It is expected that companies competing in a deregulated electricity market will achieve fairly substantial levels of cost reductions. After 2003, RDI assumed that fixed O&M will increase at the rate of inflation."

As is the case for administrative and general expenses, his statement is not supported by empirical analysis presented in his testimony.

Q. Can Mr. Seiple's analysis be compared to aggregate production cost data from Edison's FERC Form 1?

A. Yes. I have summed costs from the individual generating units included in Mr. Seiple's Exhibit CDS-11 and compared this data to costs recorded in Edison's 2000 FERC Form 1. My analysis highlights the following data problems:

1) Mr. Seiple assumes Edison's plants will generate about 55,447 GWH. According to data in the FERC Form 1 in the past few years,

Line
No.

actual generation has been 49,985 GWH in 2000, 52,500 GWH in 1999, 51,259 GWH in 1998 and 47,684 GWH in 1997.

2) Capacity factors for individual Edison plants projected by Mr. Seiple are very different from actual capacity factors. For instance, in the case of the St. Clair units, the actual capacity factor in 2000 was 59% while Mr. Seiple assumes 82%. For Trenton Channel the actual 2000 capacity factor was 59% while Mr. Seiple assumes a capacity factor of about 75%. For Marysville, the actual capacity factor was less than 10% while Mr. Seiple projected 45%.

4. Mr. Seiple's computation of total non-fuel expense plus administrative expense was $496 million while the actual total for Edison including administrative and general expenses and other items such as general plant depreciation and operation and maintenance not directly associated with individual plants in 2000 was $666 million.

5. Mr. Seiple's property tax computations result in an aggregate dollar amount for property taxes of $94 million while actual non-income taxes associated with production were $163 million.

Q. How have you corrected Mr. Seiple's analysis to reflect publicly available

Line No.

data presented in Edison's FERC Form 1?

A. Yes. I have made the following adjustments to his plant by plant cash flow analysis:

1.) I have used actual capacity factors in 2000 as a starting point and changed generation on a plant by plant basis in the same manner as used by Mr. Seiple.

2.) I model fixed operation and maintenance expenses and administrative expenses on a plant-by-plant basis from FERC data.

3.) I compute general taxes from data in the FERC Form 1 rather than using Mr. Seiple's arbitrary 1% assumption.

4.) I apply actual data on fuel expenses per MWH and I escalate these dollar per MWH amounts using Mr. Seiple's fuel expense per MWH growth rate.

5.) I use actual amortization of Fermi from the 2000 FERC Form 1.

Q. After making these adjustments, how do the Edison costs compare with actual data and with Mr. Seiple’s assumptions?

A. As I stated above, actual Edison costs from the FERC Form 1 for the year

2000 are almost 19% greater than Mr. Seiple’s first year assumptions on a dollar per MWH basis. After making the corrections described above, the modeled Edison costs are within 1% of actual costs.

Q. Does your corrected analysis directly consider securitization?

A. No. Neither my corrected analysis nor Mr. Seiple's analysis changes cost of capital assumptions associated with Fermi. Since securitization savings are provided to customers, the valuation analysis can be performed without securitization. In other words, if securitization was included, Edison's financial loss from providing rate reductions and other uses should also be reflected. However, since securitization reduces the regulated portion of generation rates, customers are able to take advantage of a lower "strike price" in returning to regulated service. This increases the stranded exposure of Edison. I have performed a sensitivity analysis that confirms this fact.

Q. After correcting the analysis to account for FERC Form 1 data, how does the value of Edison's assets change?

A. The following table demonstrates that incorporating actual public data and correct tax depreciation reduces that market value of Edison's plants by $1.9 billion.

Line No.

Value of Edison's Plants Using RDI Electricity Price Projections and Cost of Capital ($ 000's)				
	RDI Estimated Book Value at 12/31/00	Market Value of Assets per Chris Seiple Testimony	Market Value of Assets Corrected for Tax Depreciation	Market Value of Assets Corrected for Tax Depreciation and FERC Form 1 Data
Steam	2,270,674	5,563,648	4,641,261	3,533,769
Nuclear	2,333,000	-	-	-
Pumped Storage	94,415	94,695	78,538	155,342
Gas Turbines	200,339	42,978	82,706	96,117
Total	4,898,428	5,701,320	4,802,505	3,785,228
Change in Value			(898,815)	(1,017,276)
Cumulative Change in Value				(1,916,092)

Section Nine

RDI's Cost of Capital Assumption

Q. Describe Mr. Seiple's cost of capital assumption for discounting market-based cash flows?

A. In his testimony, Mr. Seiple rather casually testifies that 14% is an appropriate equity cost for market based cash flows. Further, he assumes that 60% debt financing occurs throughout the life of a merchant power project. Mr. Seiple justifies his assumptions with the statement "These assumptions are consistent with my experience working with investment banks, merchant plant developers, and potential acquirers of assets." (Seiple testimony at page 20.)

Actual financing of merchant power plants includes banking fees, debt

Line
No.

service funds that cover one year of debt service and other costs. More importantly, the capital structure in the financing of power plant is not constant over the course of a project, but the debt leverage ratio eventually declines to zero. Including banking fees, a debt service fund and a realistic maturity structure for debt significantly affects the cost of capital even if Mr. Seiple's inappropriate return on equity assumption is used.

Q. How have you corrected Mr. Seiple's cost of capital analysis to consider appropriate debt maturity terms, banking fees and a debt service reserve account?

A. I have used a simple model assuming that an asset with a twenty-year life realizes an internal rate of return of equity of 14%. I also use an assumption that at the initial valuation date, the debt leverage is 60%. Next, I added the assumption that the debt has a maturity of fifteen years. When the fact that debt must be paid off is added to the analysis, the required internal rate of return on free cash flow in order to achieve an internal rate of return on equity of 14% is 10.06% rather than the 8.8% discount rate used by Mr. Seiple. This higher cost of capital is the result of the fact that debt leverage of the project declines over time as the debt is paid off.

Inclusion of a one-year debt service fund that is commonly required for

merchant plants and banking fees of 1% increases the cost of capital required on free cash flows to 10.46%. Therefore, after correcting for the debt maturity structure and financing fees, Mr. Seiple's discount rate changes from 8.8% to 10.46%. I have also performed this analysis with a 16% and a 15% internal rate of return on equity rather Mr. Seiple's assumed equity cost of 14%. Using the 16% return on equity assumption increases the overall cost of capital increases to 11.46%. If an internal rate of return on equity is 15% is assumed, the overall cost of capital is 10.9%.

I have computed the effective equity return in a situation where a project earns an internal rate of return on free cash flow of 8.8% per Mr. Seiple's testimony. This analysis demonstrates that if a merchant project earns 8.8% on free cash flow and is financed with 60% debt, the actual earned internal rate of return is only 10.7% instead of the 14% assumed by Mr. Seiple.

Q. How does the increase in cost of capital affect valuation of Edison's assets?

A. Mr. Seiple's cost of capital assumption significantly affects valuation of Edison's assets. The table below demonstrates that use of a discount rate

Market Value of Edison's Non-Nuclear Assets without Option
($ 000's)

Discount Rate	Equity IRR	Market Value of Assets Corrected for Tax Depreciation and FERC Form 1 Data	Reduction in Value From RDI Incorrect Cost of Capital Estimate
8.80%	10.70%	$ 3,785,228.44	
10.46%	14.00%	$ 3,177,818.06	$ (607,410.38)
10.90%	15.00%	$ 3,038,456.73	$ (746,771.71)
11.46%	16.00%	$ 2,871,647.80	$ (913,580.64)

Line No.

of 10.46% rather than Mr. Seiple's assumption of 8.8% decreases the market value of Edison's assets by $607 million (this analysis uses the corrected cost data discussed above). If a 16% equity return is used rather than 14%, the reduction in value is $914 million.

Section Ten

<u>Correction of RDI's Analysis to Reflect the Value of Edison's Obligation to Provide Power at Regulated Rates without Considering Volatility</u>

Q. After correcting Mr. Seiple's analysis for problems related to tax depreciation, data problems and cost of capital, how have you proceeded with evaluation of the ABATE valuation analysis?

A. In this section I begin by computing the value of the customer option to switch between regulated service and market rates. Next, in section eleven I add volatility to the analysis. Finally, in section thirteen I relax restrictive assumptions with respect to customer behavior.

Q. What assumptions are necessary to add the valuation impacts of customer options to Mr. Seiple's analysis in the case with no volatility in

electricity prices?

A. If there is no volatility in prices, valuation of an option requires analysis of the times at which the option is exercised (i.e., when the option is "in the money" or "out of the money") as well as the value of the difference between the realized price and the exercise price option when the option is exercised. In addition to assumptions on market prices and regulated rates, it is necessary to make assumptions with respect to how the option to switch between regulated service and retail open access will work in practice and how customers will utilize their ability to exercise the option in order to value the customer option that I have been discussing. Before describing how I correct Mr. Seiple's valuation to appropriately value the option, I discuss assumptions with respect to consumer behavior that I have made in the analysis.

Q. Please summarize the initial assumptions you have used to correct analytical fallacies in Mr. Seiple's discounted cash flow method?

A. In quantifying conceptual errors in Mr. Seiple's analysis that arise because he did not consider the value foregone by Edison from offering customers insurance against high market prices I make certain initial assumptions with respect to customer behavior. Later, I change these assumptions and demonstrate that my conclusions with respect to bias in Mr. Seiple's analysis from netting discounted cash flows still exists. My initial assumptions include:

1) Customers have information with respect to market price levels that will be present in the next year;
2) Customer decisions to select open access service or regulated service can be gauged from aggregate cost per kWh data on the generation portion of bundled rates and aggregate market clearing prices rather than on class specific information with respect to market prices and regulated rates;
3) Mr. Seiple's market price forecasts will turn out to be true and there is no uncertainty associated with his price forecast;
4) Edison's cost per MWH of generation will turn out to be consistent with costs developed in the previous section; and,
5) Customers select market based pricing or regulated tariffs depending on which option results in lower electric bills without a time lag and without a "hurdle" savings criteria.

Q. What assumption have you made regarding the right of customers to switch from retail open access service at market based pricing to regulated tariffs.

A. In this part of the analysis, I assume that customers know what prices will be for the next year and that they can switch back and forth between regulated rates and market prices as a function of actual market prices for the year. I understand that customers in fact must make lock into

Line No.

decisions for a period of one year, and that perfect foresight with respect to market clearing prices does not exist. However, I have initially used this “foresight” assumption for three reasons. First, the analysis is simpler with this assumption and adding the complexity of a one-year uncertainty adds complexity to the analysis without altering the fundamental points. Second, since market prices are a function of merchant capacity, economic activity, primary fuel prices and other factors that are reasonably known ahead of time, the assumption of one year foresight is reasonable. Third, I relax the assumption in a subsequent section of my testimony and I demonstrate that it does not have a significant impact on my conclusions.

Q. Please describe your assumption with respect to use of aggregate embedded costs and overall market prices rather than segregated customer class analysis.

A. The choice a customer will make in the future between regulated rates and market-based prices is a function of the specific tariff levels and market-based prices faced by that particular customer. Edison has proposed the ECTA mechanism so that the decision faced by different groups of customers will be not biased by the structure of current tariffs. If the ECTA mechanism is adopted, it is reasonable to assume that the aggregate generation portion of regulated rates on a dollar per MWH basis and aggregate level of market prices for the system are representative of individual customer decisions. However, if the ECTA proposal is not

adopted, the value of customer options dramatically increases because some customers will almost always be “in the money” through selecting market prices while others will almost always be better off with regulated tariffs.

In this part of my testimony I assume that all customers face the same market price and all customers have the same tariffs and generation component of bundled rates, i.e., the assumption is that Detroit Edison’s ETCA adjustment is approved.

Q. What assumptions have you made with respect to consumer behavior regarding the amount of required savings before switching between market based rates and regulated rates in order to correct the analysis presented by Mr. Seiple?

A. In this part of my testimony I make the assumption that current Edison customers select the pricing alternative that results in the minimization of their electric bills. This means that I do not assume customers will delay their decision for a certain period of time if it is economic to switch between regulated service and retail open access service. Also, I do not assume that there is some kind of hurdle savings criteria before which customers will switch between regulated service and retail direct access service. That is to say, there is no customer inertia in customer decision making. Later in the testimony I quantify implications of changing this

Line No.

assumption

Q. How have you corrected Mr. Seiple’s valuation analysis to appropriately consider the value that customers gain from the option to secure service under regulated rates using the above assumptions?

A. Assuming no volatility in market prices, customer foresight and no inertia allows Mr. Seiple’s analysis to be corrected in a straightforward manner to consider the value of the option. I simply assume that each year the market price is below the generation portion of bundled rates that Edison cannot realize the positive cash flow that Mr. Seiple assumes the Company can monetize in his valuation. When the market price is above the regulated rate, I substitute cost-based cash flows for the regulated cash flows. The valuation therefore uses market-based cash flows in some periods and cost based cash flows in other periods.

Q. How does correction of Mr. Seiple’s analysis to consider the value of customer options in Michigan affect the valuation of Edison’s assets?

A. Using the corrected assumptions and the discount rate of 10.46%, the customer option is $1.567 billion. Inclusion of the option reduces the market value of Edison assets from $2.745 billion without valuation of the option to $1.178 billion with the option included. (This valuation includes Fermi as well as the other fossil and hydro assets.) If the Mr. Seiple’s cost assumptions are accepted, the value of the option is greater. In this case,

Line No.

the option has a value of $1.897 billion, which reduces the value of Edison's assets from $3.856 billion to $1.959 billion.

Section Eleven

<u>Correction of RDI's Analysis to Reflect the Value of Edison's Obligation to Provide Power at Regulated Rates With Inclusion of Price Volatility in the Plant Valuation</u>

Q. How does volatility in a price series affect the value of an asset if there is an option associated with the asset?

A. Other things being equal, the greater the volatility of prices, the more the value of an option. This is just as true for call options on stocks as it is for the option customers have to return to regulated generation service in Michigan. If you own a call option on a stock and if there is a great deal of variation in the price, you have more of a chance to make a lot of money because the stock price might reach very high levels. On the other hand, your downside is limited because you do not have to exercise the option. The same sort of thing exists for customers who can select regulated service at cost based rates if market prices reach high levels. The more the volatility of prices, the greater the value of the option to use regulated generation service because the downside risk is limited.

In this section of my testimony I add volatility to correction of Mr. Seiple's valuation analysis. To consider how volatility affects value to Edison and its customers, I do not change assumptions with respect to customer behavior. When adding volatility to the analysis, I also incorporate other "time series" elements including price boundaries and mean reversion.

Q. What is the relevant definition of volatility for purposes of analyzing value implications of the option that consumers have in Michigan to receive either regulated or open access service?

A. Volatility is generally defined as the standard deviation of the percent change in a price series on an annual basis. Computation of volatility from historic data involves first measuring the rate of return (the log of this period's price divided by the previous period's price). Next, one computes the standard deviation of the rate of return percentage. If the time period of historic price data is annual, the volatility can simply be computed as the standard deviation of the percent change in prices.

In the case of electricity, measured volatility using daily prices can be very high because of price variation driven by changing weather, price spikes, seasonal price patterns, on-peak versus off-peak prices and supply shortages. Long-term volatility is generally less than the short-term volatility because over the course of a year, factors such as weather, outage-related supply shortages, and seasonal price patterns "average

out." In the long-term, volatility of electricity prices is driven by volatility in capacity prices, volatility in natural gas prices, volatility in the productivity of new technology, volatility in annual demand, and in some cases volatility in hydrology conditions. It is long-term volatility rather than short-term volatility that is required for analysis of the option value realized by customers from the option to switch between market based rates and regulated rates.

Q. Other than price volatility, what "time series" parameters are necessary to represent the movement of prices around expected forward prices in order to correct Mr. Seiple's analysis?

A. The movement of electricity prices is driven by volatility as well as mean reversion parameters and boundary conditions. There is a lower bound on electricity prices defined by short-run marginal energy costs because if prices are below marginal cost, companies will not operate plants. Mean reversion exists in electricity prices because competitive electricity prices are driven by supply and demand conditions, implying that the prices come back to levels determined by the cost of production. An upper bound on electricity prices is also reasonable to assume because of price elasticity of demand and supply. A time series equation that includes volatility, mean reversion and boundary conditions can be represented using the following formula:

Line
No.

Price (t) = Price (t-1) +
Mean Reversion Factor x (Price(t-1) – Equilibrium Price) +
Volatility Percent x Price(t-1) x Draw from Normal Distribution

[Subject to lower bound and upper bound conditions]

Q. Can historic data on electric prices be used to estimate long-term volatility?

A. Unfortunately not. There is not enough historic data on competitive prices to establish volatility and mean reversion parameters. Furthermore, changes in the structure of the market imply that past data may not be appropriate for estimation of future volatility even if historic data did exist. Therefore, given problems in using historic data to estimate future volatility, one must use judgment to develop time series parameters. Because of the difficulties in developing precise time series models for the purpose of measuring option value, I use a range of volatility estimates.

Q. Describe economic factors that create long-term volatility in electricity prices?

A. Long-term volatility in electricity prices is driven by a number of supply and demand factors including the following:

1.) There have been prolonged periods -- sometimes lasting many years -- of very low or zero capacity prices driven by slow demand and excess

capacity. Since prices can be at levels which do not justify construction of new capacity for many years, this implies a high degree of volatility in capacity prices.

2.) Other competitive capital intensive industries with large construction projects such as mining and real estate have a high level of price volatility.

3.) There have been significant changes in the productivity of generating assets as evidenced by reduced real per kW cost and reduced heat rates for combined cycle plants and the increased capital costs of nuclear plants from the 1970's to the 1980's.

4.) Primary fuel prices for natural gas and oil significantly affect electricity prices and these commodities have high long-term volatility.

5.) A large amount of year to year price variation can occur because of hot summers, cold winters, recessions, dry river conditions, longer than expected maintenance outages and fuel supply problems.

6.) The long life span of assets and relatively slow demand growth mean that prices move very slowly to equilibrium after a significant supply change.

Line No.

Q. Why does mean reversion exist in electricity prices over the long run?

A. If electricity prices did not move back to equilibrium or average levels, the price process would be know as a non-stationary process. “Random walk” and “Brownian motion” are examples of this price process where prices can wander indefinitely without moving back to a mean level. However, mainly because electricity prices are ultimately driven by forces of supply and demand, they eventually move back to the long-run cost of production. Therefore, mean reversion parameters must be estimated along with volatility in developing a time series model. Some of the determinants of the level of long-term mean reversion in electricity prices include:

1.) Reversion back to the mean after price changes caused by fluctuations in weather related demand is fast, if not immediate. If prices change because of a hot summer or a cold winter, these factors should not re-cur in the next period. On the other hand, demand changes due to variation in general economic conditions have impacts that last over the course of a business cycle, suggesting a slower rate of mean reversion.

2.) Reversion back to the mean after a “price shock” in capacity prices can take a long period of time. If capacity prices are low because of

Line No.

surplus capacity, then plant retirements and load growth are required to move capacity prices back up to equilibrium levels. If capacity prices are high, the time lag in new plant construction drives the mean reversion.

3.) The mean reversion resulting from price shocks caused by changes in primary fuel prices is the mean reversion in these price processes. For example, the time series process for oil and natural gas is known to be mean reverting as exploration and production reacts to price changes.

4.) Price changes that arise from changes in productivity of new generating resources probably do not revert to a mean level and should follow a random walk process.

Q. What volatility, mean reversion and boundary condition assumptions have you made in computing the option value from the ability of customers to switch back and forth from regulated service to market based rates in order to correct Mr. Seiple's analysis?

A. Even though the long-term volatility of electricity is probably below short-term volatility, because of volatility related to capacity prices, long-term load growth, primary fuel prices, and other factors, it is reasonable to expect the annual volatility in electricity prices to be high relative to the

volatility of other commodities and financial instruments. Since 1978, the long-term volatility in real prices of crude oil and natural gas has been above 20%. Because of the sources of volatility described above, I believe the volatility of electricity prices on a long-term basis is relatively high. In order to cover different possible outlooks with respect to long-term volatility in correcting Mr. Seiple's analysis, I have assumed annual electricity prices volatility of 10%, 15%, 20%, 25% and 30%.

I have made the following assumptions with respect to time series parameters other than volatility:

1.) I assume a mean reversion parameter of 25% which implies that after a "shock", electricity prices move back to within 68% of the mean "equilibrium level" within four years.

2.) I assume a lower boundary on prices of $15/MWH, which is intended to approximately reflect the levels of short-term marginal cost in ECAR.

3.) I assume an upper bound on all-hour (both on-peak and off-peak) prices of $60/MWH that accounts for construction of peak capacity and interruption in loads when prices rise to very high levels.

4.) I assume that the lower and upper bound prices escalate with the overall rate of inflation assumed by Mr. Seiple.

Line No.

Q. How have you applied the time series parameters to Mr. Seiple's price projections?

A. I have applied the time series parameters to Mr. Seiple's price projections using the following formula (where his price forecast is the RDI price):

Price (t) = Price (t-1) +
25% x (Price(t-1) – RDI Price(t)) +
Volatility Percent x Price(t-1) x Draw from Normal Distribution

[Subject to lower bound of $60/MWH and upper bound of $15/MWH]

The volatility percent is either 10%, 15%, 20%, 25% or 30% as described above.

Q. Once time series parameters have been established, how can the customer options to switch between regulated rates and market-based prices be incorporated in valuation analysis?

A. Three general approaches to measuring the value of an option are: (1) a mathematical equation such as Black Scholes formula, (2) binomial trees; and (3) Monte Carlo simulation. I have measured the value of customer options using the Monte Carlo simulation method rather than the other approaches because of the complex structure of the customer option and because the time series model that includes boundary conditions and mean revision does not lend itself to a mathematical equation such as Black Scholes. Operation of Monte Carlo simulation involves computing

Edison's generating plant value from 1,000 price path scenarios where the alternative price patterns defined by random draws. The random draws are computed in each period of the analysis, which means that in a twenty year analysis, there are twenty times 1,000 or 20,000 different random draws.

Q. How does the incorporation of volatility and the other time series parameters affect asset valuation for Detroit Edison?

A. In some of the Monte Carlo scenarios, market prices are relatively low, stranded investment is high and the customer option to return to tariff rates is not very important. In other scenarios, the market prices are relatively high and the option to cap rates at regulated levels is exercised often by customers. If the customer option to cap rates did not exist in Michigan restructuring, inclusion of volatility in the analysis would not significantly change the final discounted cash flow computation. Without the option, some draws from the simulation would have high value and others would have low value, but on average the valuation would be about the same as if no volatility was included in the analysis.

When the customer option is included in the valuation analysis, volatility increases value to customers because the benefits to customers of low price scenarios are fully incorporated in the asset valuation, but customer costs in the high price scenarios are limited. Therefore, the distribution of

Line No.

cash flows across scenarios is truncated. In other words, the customer upside is not restricted, but the downside is limited due to the cap from regulated rates. Of course, the increase in value to customers caused by volatility is at the same time a reduction in value to Detroit Edison.

Q. Summarize the valuation of Detroit Edison assets that incorporates volatility of 10%, 15%, 20%, 25% and 30% in electricity prices.

A. Without price volatility, the value of Edison's assets in a restructured environment using Mr. Seiple's market price forecasts is $1.178 billion as described above. When 10% volatility in market prices and the other time series parameters are included in the analysis, the market value of Edison's generation assets becomes $1.085 billion. With volatility of 20%, the market value of Edison's assets declines to $924 million and with volatility of 30%, market value is $555 million. The effects of price volatility on the valuation of Edison's generation assets is shown on the

Valuation of Edison Assets Assuming Optimal Customer Behavior and RDI Prices

($ 000's)

	Corrected Cost Assumptions		RDI Cost Assumptions
Cash Flow Value Before Option	$ 2,744,975		$ 3,856,432
Cash Flow Value after Option - No Volatility	$ 1,177,993		$ 1,958,980
Cash Flow Value After Option - 10% Volatility	$ 1,084,723		$ 1,846,826
Cash Flow Value After Option - 15% Volatility	$ 1,017,466		$ 1,697,828
Cash Flow Value After Option - 20% Volatility	$ 924,836		$ 1,496,478
Cash Flow Value After Option - 25% Volatility	$ 747,368		$ 1,192,758
Cash Flow Value After Option - 30% Volatility	$ 555,495		$ 875,153

Line No.

Section Thirteen

Adjustments to the Value Analysis to Account for Non-Optimal Customer Decisions and Volatility in Regulated Rates

Q. Could you please review the assumptions that you have incorporated in the above analysis with respect to customer behavior.

A. The above analysis assumes customers make rational decisions and that they have full knowledge of current market prices. Therefore, customers switch between bundled rates and market rates as soon as they can earn a penny, and, since customers lock into decisions for a one year period, I implicitly assumed that they know what prices will be for the next year before they make their decision.

In this section I modify these assumptions with respect to customer behavior. I demonstrate that changing the assumptions on customer behavior does not have a large impact on the valuation analysis. The conceptual problems in Mr. Seiple's valuation analysis still negate using his method for purposes of establishing transition charges.

Q. How have you changed assumptions with respect to optimal customer behavior?

A. First, I assume that customers make the decision to switch between regulated rates and market rates using prices in the previous year rather than prices in the current year. Second, I assume that customers require a relatively large 7% savings hurdle before they make a decision to change to or from market based rates.

These two assumptions have the effect of reducing the cost of Edison's obligations associated with the customer call option. If customers cannot make decisions on actual prices, there will be some periods when customers are not able to take advantage of low market prices – reducing Edison's stranded investment exposure. In addition, without the perfect foresight, there will be other periods when customers will not exercise their option to return to regulated service even when the switch would have been beneficial. If customers require a 7% hurdle before switching to or from market rates, Edison's stranded investment during low price periods is reduced and there are some periods when customers do not appropriately exercise their option to return to regulated rates.

Q. How does volatility in regulated rates affect measurement of the value of Edison's plants in a restructured environment?

A. The effect of volatility in regulated rates on the valuation of Edison's assets depends on the relationship between volatility in market prices and volatility in regulated rates. If the volatility in regulated rates is

independent of volatility in market prices, the valuation of Edison's assets is not affected by inclusion of volatility in regulated rates. On the other hand, if volatility in regulated rates is such that regulated prices move in the same direction as the market prices, valuation impacts of the customer option are reduced.

To illustrate why volatility in a cost that is independent of market price does not affect valuation of the customer option, consider the case of variation in the operation and maintenance costs of Fermi. If one assumes no relationship of Fermi operation and maintenance cost to market prices, then in some scenarios, Fermi costs will be higher than average levels, and at other times, the costs will be lower than average. In the scenario when Fermi costs are lower, the capped “strike” price is reduced and the customer option is more valuable. On the other hand, when the Fermi costs increase, the capped “strike” price is increased and the option to return to regulated service is less valuable. However, the volatility in the “strike price” resulting from changes in Fermi costs does not bias the overall valuation in one direction or another.

Q. If volatility in Edison costs is positively correlated with market price volatility, how is valuation affected?

A. If volatility in generation costs is perfectly correlated with market prices, then the value of the option to switch between regulated service and

Line No.

market rates is diminished. In this case, when the market price goes up, if the regulated rate also goes up, the option to insure against high market prices and return to regulated service is less valuable.

Q. What adjustments in Mr. Seiple's valuation analysis have you made so as to incorporate volatility in Edison regulated rates and generation costs?

A. Generation costs consist of the return on existing assets, fuel expenses, non-fuel operating and maintenance expenses, administrative and general expenses and taxes. Most of these items do not have volatility that is positively correlated with market price volatility. For example, the cost basis of existing assets does not vary with market prices, and there is little reason to expect that non-fuel expenses will change when market prices change. On the other hand, it is reasonable to presume that when natural gas and oil prices change significantly, electricity prices will vary in a similar manner.

In modeling the volatility of Edison's generation costs, I assume that the percent change in gas and oil prices is the same as the overall percent change in electricity prices relative to the base prices. For example, if a particular scenario in the Monte Carlo analysis results in electricity prices that are 20% above the Mr. Seiple's forecast, the natural gas prices are also assumed to be 20% above the base case forecast.

Q. What is the effect of the alternative assumptions with respect to customer behavior and inclusion of volatility in regulated rates on the corrections to Mr. Seiple's valuation analysis of Edison's generating assets?

A. The table below illustrates valuation of Edison's generating plants with alternative assumptions for customer behavior and volatility in regulated prices. The structure of the valuation model – use of Mr. Seiple's electricity price projections, assumptions with respect to the cost structure of Edison's assets and the time series equation -- is the same in the model without the different customer behavior assumptions. However, the assumed decision making process used by customers reflects inertia and the volatility related to oil and gas prices is included in regulated rates. Relative to the market value of $5.7 billion computed by Mr. Seiple, this alternative analysis demonstrates that a more appropriate estimate of the value of Edison's plants is between one and two billion dollars.

I have computed the required transition charge using valuation results from the table below. For instance, in the case assuming Mr. Seiple's cost assumptions instead of the corrected cost analysis as well as the less favorable assumptions with respect to customer behavior and volatility in regulated rates, the required transition charge is more than $12/MWH.

Line
No.

Valuation of Edison Assets Assuming Inertia in Customer Behavior and RDI Prices ($ 000's)			
	Corrected Cost Assumptions		RDI Cost Assumptions
Cash Flow Value Before Option	$ 2,744,975		$ 3,856,432
Cash Flow Value after Option - No Volatility	$ 1,222,648		$ 2,039,174
Cash Flow Value After Option - 10% Volatility	$ 1,184,457		$ 2,070,903
Cash Flow Value After Option - 15% Volatility	$ 1,165,465		$ 2,052,621
Cash Flow Value After Option - 20% Volatility	$ 1,140,426		$ 2,028,745
Cash Flow Value After Option - 25% Volatility	$ 1,057,339		$ 1,890,274
Cash Flow Value After Option - 30% Volatility	$ 939,454		$ 1,721,511

Section Fourteen

Analysis of the Energy Michigan Proposal on Transition Charges

Q. How does the stranded recovery mechanism presented by Energy Michigan compare to Detroit Edison's proposal?

A. The transition charge formula presented by Energy Michigan's witness, Mr. Polich, is geared to benefiting direct access customers at the expense of customers who retain regulated service from the incumbent utility company. The mechanism by which Mr. Polich achieves a favorable outcome for retail direct access customers involves allocating the aggregate amount of production cost reductions to direct access customers rather than computing adjustments to the transition charge on

Line No.

an incremental basis.

Q. Does Mr. Polich imply that retail open access customers do not receive securitization savings?

A. Yes. Mr. Polich discusses how securitization savings should affect the transition charge formula:

> If a revenue requirement method is used to calculate stranded cost, it calculates the revenue requirement associated with the utility cost of production. That cost of capital component would be lower due to the lower capital costs produced by securitization. But it must be remembered that the utility revenue side will also be lowered because the utility will be giving its customers a 5% rate reduction. Thus, in the calculation of a transition charge by the revenue requirement method, the lower cost of capital which reduces revenue requirement also reduces the revenues available to pay that requirement. On the other hand, retail bundled sales customers will have recovered a net 5% rate reduction. . . . some means must be found to deliver to ROA customers the same net rate reduction that is given to bundled sales customers."

Mr. Polich also states: "The proposals of Consumers and Edison . . . divert excess securitization savings to pay ROA implementation costs instead of reducing transition charges. (Polich testimony at page 25.)

Q. Does Edison's proposal provide that retail open access customers directly realize benefits from securitization rate reductions?

A. Clearly, it does. Mr. Falletich shows a lower generation break-even price in 2001/2002 than in 2000 because of the securitization rate reduction on

Line No.

his exhibit ELF-1 (see the difference between rates in columns d and e). Then, in demonstrating mechanics of the economic benefit/harm portion of the transition charge, Mr. Zakem's exhibit AJZ-4 begins with the retail rate from Mr. Falletich's exhibit ***after*** the securitization rate reduction. Therefore, the economic harm charge to customers is reduced (or the economic benefit credit is increased) because of the securitization rate reduction.

Q. How much would the transition charge increase on Mr. Zakem's exhibits if securitization rate refunds were not incorporated in the economic harm/benefit charge?

A. Problems with Mr. Polich suggestion that retail open access customers do not receive benefits from the securitization rate reduction are clear if one works through the examples presented by Mr. Zakem. On page 1 of Exhibit AJZ-4, the average class revenue would increase by 0.33 cents/kWh (from 6.10 to 6.43) if the rate decrease from securitization was not deducted from the “average class per-unit revenue” on line 1 for primary customers. This increase in the average class per-unit from not considering the securitization rate reduction would increase the per unit economic harm charge by the same amount. Mr. Zakem's exhibit therefore demonstrates that Edison's method in fact does precisely what Mr. Polich recommends.

Line
No.

Q. What are the most significant differences between Mr. Polich's proposal and Edison's method with respect to transition charges?

A. Mr. Polich's formula seems quite similar to the formula presented by Mr. Zakem. However, there is a significant difference between his proposal and the Edison method for computing economic harm or benefit involving calculation of transition charges from aggregate production costs rather than incremental changes. As I explain below, computation of transition charges on a company-wide basis using Mr. Polich's approach is inequitable to customers who remain on bundled rates. Mr. Polich's approach favors direct access customers to the detriment of customers who desire to retain regulated service.

Q. What is wrong with using aggregate company-wide generation costs rather than incremental costs in computing transition charges?

A. Given features in the Michigan restructuring program that maintain regulation for customers who choose to retain service from the incumbent utility company, equitable rates must be established for those customers who continue to select services from the incumbent utility company as well as those customers who choose retail open access. However, if Mr. Polich's method is used in the situation where aggregate generation costs are declining, the total company-wide cost reduction is allocated to customers who choose open access. If relatively few customers select retail open access, Mr. Polich's method virtually assures that they will not

pay a transition charge in the declining cost scenario.

The approach suggested by Mr. Polich is inequitable to Edison regulated customers because it makes them "second class citizens" with respect to receiving the benefit of reduced production costs. Indeed, it is possible that retail open access customers would receive all of the benefits of a reduction in production costs while regulated customers would receive no benefits.

Q. If Edison's production cost per kWh increases because of a decline in sales, what would happen under Mr. Polich's approach?

A. Under Mr. Polich's approach, if production costs increase, the transition charge could become very large because the total impact of the increased cost is allocated in the transition charge to retail direct access customers. However in this scenario, the transition charge would be so high that customers would probably return to regulated service. Therefore, while direct access customers get an extraordinary benefit when costs decline, the method is not symmetric. Instead, direct access customers are protected when costs increase.

Q. Please describe how Mr. Polich's method affects direct access customers and customers who retain service from the incumbent utility company using a simplified example with alternative sales growth assumptions.

A. The mechanics by which Mr. Polich's method favors direct access customers at the expense of customers who retain regulated service is subtle. Therefore, I have used a simplified example with alternative sales growth scenarios to illustrate how both regulated customers and direct access customers are affected by Mr. Polich's recommendation. This example is illustrated in the table below:

	Base	Sales Increase of 25 MWH	Sales Increase of 50 MWH	Sales Increase of 100 MWH
Stranded Cost	$ 2,000.00	$ 2,000.00	$ 2,000.00	$ 2,000.00
Variable Cost/MWH	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Sales (MWH)	100	125	150	200
Total Variable Cost	$ 3,000.00	$ 3,750.00	$ 4,500.00	$ 6,000.00
Total Cost: (Stranded Cost + Variable Cost)	$ 5,000.00	$ 5,750.00	$ 6,500.00	$ 8,000.00
Total Cost/MWH	$ 50.00	$ 46.00	$ 43.33	$ 40.00
Base Transition Charge	$ 20.00			
Polich Method of Allocating Aggregate Cost Change to Retail Open Access Customers				
Extra Revenue Net of Variable Cost		$ 500.00	$ 1,000.00	$ 2,000.00
Change in Transition Charge - Polich Method		$ (5.00)	$ (10.00)	$ (20.00)
Retail Rate - Polich Method		$ 50.00	$ 50.00	$ 50.00
Edison Method of Allocating Incremental Cost Change to Retail Open Access Customers				
Change in Transition Charge - Edison Method		$ (4.00)	$ (6.67)	$ (10.00)
Retail Rate - Edison		$ 46.00	$ 43.33	$ 40.00

In the above table, the initial retail rate for generation is 5 cents per kWh and the market rate is 3 cents per kWh. The table demonstrates the operation of Mr. Polich's approach and how Edison's proposal would work after the rate freeze period. In the simplified example, the rates for customers who choose regulated service do not decline under Mr. Polich's method even though stranded investment is spread over a larger sales base. On the other hand, under Edison's approach (after the rate freeze period) both regulated and retail open access customers benefit from

Line No.

reductions in average cost per kWh.

Q. Isn't your example inappropriate because of Edison's rate freeze and because Edison's rates do not always equal its costs?

A. No. I demonstrated earlier Edison is currently just about earning its allowed return. If there is no change in cost per kWh as compared to allowed rates, there is no difference between Edison's transition charge approach and Mr. Polich's method. Therefore, the more important policy implications of Mr. Polich's recommendation are long term effects. Secondly, the fact that costs do not necessarily match rates in each period is a general aspect of regulation. The difference between costs and rates is not a reason to provide all benefits of cost reductions to retail open access customers to the long-term detriment of customers who choose regulated service.

Part Fifteen

<u>Miscellaneous Comments on ABATE's Position and Comments on Recommendations Made by Witnesses Sponsored by the Attorney General</u>

Q. Do you agree with Mr. Seiple's comments with respect to increases in asset value that occur in a sales auction?

A. I disagree with the following statement that Mr. Seiple's makes in his testimony:

Line No.

> I would expect an actual sale of the assets to yield a higher market value and lower stranded cost than out DCF approach for two reasons. First, in an auction the market value is typically determined by the buyer that perceives that highest value for the assets. Thus, the buyer who has the most aggressive expectation regarding future cost reductions tends to determine the market price." (Seiple testimony at page 30.)

Mr. Seiple is essentially suggesting that the Commission should attempt to take advantage of market imperfections which may result in asset purchasers paying too much for Edison's generating assets. In general, I believe attempting to "play the market" is bad business policy and bad regulatory policy. If Mr. Seiple's suggestions are adopted, then the Commission and Edison should attempt to "sell high" by timing the market. I suggest that the focus should be on developing balance equitable and efficient policy rather than hoping a buyer will over pay for Edison's generating plants.

Q. Should Edison divest its plant because a purchaser may be able to exercise market power and thereby increase the bid price for a generating asset?

A. No. Dr. Tabors, Mr. Seiple and Mr. Selecky all claim that a divestiture will result in higher valuation than a valuation using a cash flow approach. Dr. Tabors elaborates how market prices of electricity have been above marginal cost and how this justifies a higher plant valuation through

Line No.

simulation of a divestiture. His notion is essentially that electric power markets are inefficient and that bidders will pay more for an asset because the ability to exercise market power will exist. The suggestion to divest assets in order to gain higher transaction prices because of the ability to exercise market power is bad regulatory policy. There are certainly no savings to customers in this scenario. If Edison customers receive benefits from lower stranded investment, the benefits are lost when they pay more in power prices. The asset value increase resulting from asset divestitures that result in exercise of market power is purely illusory at best and very dangerous policy at worst.

Q. Please summarize recommendations made by witnesses sponsored by the Attorney General.

A. Mr. King recommends that Edison's economic harm/benefit transition charge should be rejected primarily because he asserts that "DECo's proposal, if implemented, would guarantee the failure of a truly competitive market for generated power in Michigan" (King testimony at pate 10.) He also disputes the Equalization Transition Charge Adjustment proposed by Edison and the "more ornamental" ROSA system proposed by Consumers Energy. Mr. King explains "I strongly question the advisability of contriving surcharges on some ROA customers and surcredits on others to manipulate the market response to Energy Choice in a manner that most pleases the utilities." (King testimony at page 12.)

Line No.

Mr. Peloquin makes a similar recommendation as does ABATE witness Mr. Selecky that a fixed stranded “benefit charge” should be deducted from the securitization charge: “Edison should be calculating a stranded benefit offset in order to net stranded costs and stranded benefits, that is ‘net stranded costs.’” (Peloquin testimony at page 9.) On the next page of his testimony he states that “the stranded benefit offset should be allocated on a uniform per kilowatt-hour basis.”

Q, Do you agree with the recommendations made by these two witnesses?

A. No. The recommendations made by Messrs. King and Peloquin are essentially the same as the proposals made in by ABATE. If an inflexible transition charge were adopted, the charge would have to cover Edison’s obligation to provide service at regulated prices. As I explain in my testimony above, if Edison’s financial obligations associated with the option to switch between regulated service and open access service are appropriately valued, an equitable transition charge would be much higher than the securitization charge. Further, if market prices of electricity increase, and if the economic harm/benefit charge is not approved, customers lose the opportunity to experience transition charges below the securitization charges in high market price periods. Edison has developed a workable system given the central feature of Michigan restructuring that allows customers to continue receiving regulated service.

Recommendations by Messrs. King and Peloquin do not improve on Edison's proposal.

If the ETCA mechanism were not approved per the recommendations of Messrs. King and Peloquin, Edison's transition charge would have to be high enough on customers who select open access to cover the added financial losses that occur. Estimation of financial losses would be a complex process involving assumptions with respect to customer participation, market prices and future regulated rates.

Q. Does this complete your rebuttal testimony?
A. Yes, it does.

Line
No.

Line
No.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to implement the provisions of Section 10a(10) of 2000 PA 141.	)))	Case No. U-12639

EXHIBITS

OF

EDWARD C. BODMER

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to implement the provisions of Section 10a(10) of 2000 PA 141.	)))	Case No. U-12639

WORKPAPERS

OF

EDWARD C. BODMER